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Volume 1. Technical Results

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16. ABSTRACT

The report gives results of an evaluation of combustion modification techniques for coal-, oil-, and gas-fired utility boilers, with respect to NOx control reduction effectiveness, operational impact, thermal efficiency impact, capital and annualized operating costs, and effect on emissions of pollutants other than NOx. For gas- and oil-fired boilers, 30 to 60% NOx reductions are achievable with the combined use of staged combustion, flue gas recirculation, and low excess air at an annualized cost of $0.50 to $3.00/kW-yr. For retrofit control of existing coal-fired boilers, low NOx burners and/or staged combustion yields a 30 to 60% NOx reduction at an annualized cost of $0.40 to $1.20/kW-yr. For new sources, modified furnace design with low NOx burners and/or overfire air can achieve emission levels of 260 to 170 ng/J (40 to 60% reduction). Detailed emission tests on a 200 MW coal-fired boiler showed that changes in trace specie emissions due to combustion modifications were small compared to the benefit of reduced NOx emissions.

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PREFACE

This is the first in a series of five process engineering reports documented in the "Environmental Assessment of Stationary Source NO_x Combustion Modification Technologies" (NO_x EA). Specifically, this report documents the environmental assessment of NO_x combustion controls applied to utility boilers. The NO_x EA, a 36-month program which began in July 1976, is sponsored by the Combustion Research Branch of the Industrial and Environmental Research Laboratory of EPA (IERL-RTP). The program has two main objectives: (1) to identify the multimedia environmental impact of stationary combustion sources and NO_x combustion modification controls applied to these sources, and (2) to identify the most cost-effective, environmentally sound NO_x combustion modification controls for attaining and maintaining current and projected NO_2 air quality standards to the year 2000.

The NO_x EA is assessing the following combination of process parameters and environmental impacts:

- Major fuel combustion stationary NO_x sources: utility boilers, industrial boilers, gas turbines, internal combustion (IC) engines, and commmercial and residential warm air furnaces. Other sources (including mobile and noncombustion) will be considered only to the extent that they are needed to determine the NO_x contribution from stationary combustion sources.
- Conventional and alternate gaseous, liquid and solid fuels
- Combustion modification NO_x controls with potential for implementation to the year 2000; other controls (flue gas cleaning, mobile controls) will be considered only to estimate the future need for combustion modifications

- Source effluent streams potentially affected by NO_x controls
- Primary and secondary gaseous, liquid and solid pollutants potentially affected by NO_x controls
- Pollutant impacts on human health and terrestrial or aquatic ecology

To achieve the objectives discussed above, the NO_x EA program approach is structured as shown schematically in Figure P-1. The two major tasks are: Environmental Assessment and Process Engineering (Task B5), and Systems Analysis (Task C). Each of these tasks is designed to achieve one of the overall objectives of the NO_x EA program cited earlier. In Task B5, of which this report is a part, the environmental, economic, and operational impacts of specific source/control combinations are evaluated. On the basis of this assessment, the incremental multimedia impacts from the use of combustion modification NO_x controls will be identified and ranked. Systems analysis in turn uses the results of Task B5 to identify and rank the most effective source/control combinations to comply, on a local basis, with the current NO_2 air quality standards and projected NO_2 related standards.

As shown in Figure P-1, the key tasks supporting Tasks B5 and C are Baseline Emissions Characterization (Task B1), Evaluation of Emission Impacts and Standards (Task B2), Experimental Testing (Task B3), and Source Analysis Modeling (Task D). The arrows in Figure P-1 show the sequence of subtasks and the major interactions among the tasks. The oval symbols identify the major outputs of each task. The subtasks under each main task are shown on the figure from the top to the bottom of the page in roughly the same order in which they will be carried out.

As indicated above, this report is a part of the Process Engineering and Environmental Assessment Task. The goal of this task is to generate process evaluations and environmental assessments for specific source/control combinations. These studies will be done in order of descending priority. In the first year of the NO_x EA, all the sources and controls involved in current and planned NO_x control implementation programs were investigated. The "Preliminary Environmental Assessment of Combustion Modification Techniques" (Reference P-1) documented this effort and established a priority ranking based on source emission impact and

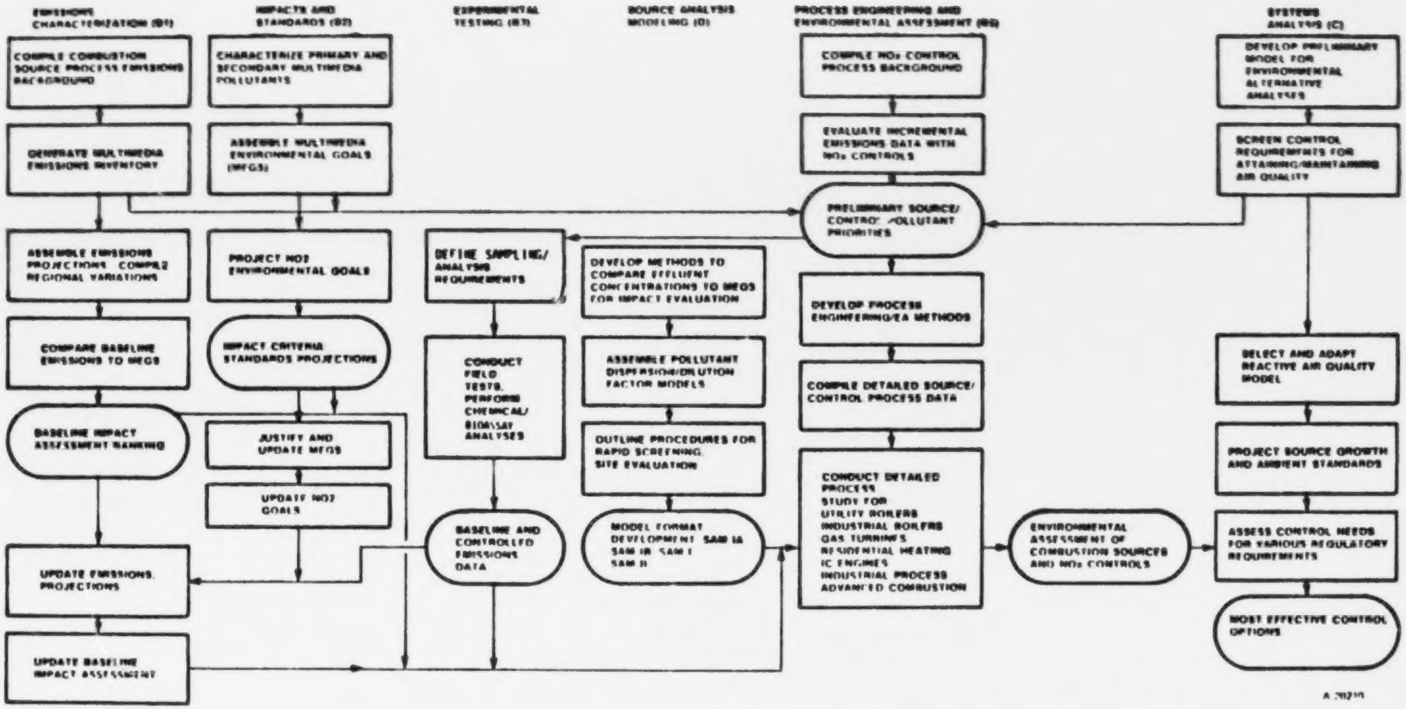
EMISSIONS CHARACTERIZATION (B1)
IMPACTS AND STANDARDS (B2)
EXPERIMENTAL TESTING (B3)
SOURCE ANALYSIS MODELING (D)
PROCESS ENGINEERING AND ENVIRONMENTAL ASSESSMENT (B5)
SYSTEMS ANALYSIS (C)
COMPILE COMBUSTION SOURCE PROCESS EMISSIONS BACKGROUND
GENERATE MULTIMEDIA EMISSIONS INVENTORY
ASSEMBLE EMISSIONS PROJECTIONS COMPILE REGIONAL VARIATIONS
COMPARE BASELINE EMISSIONS TO MEGS
BASELINE IMPACT ASSESSMENT RANKING
UPDATE EMISSIONS PROJECTIONS
UPDATE BASELINE IMPACT ASSESSMENT
CHARACTERIZE PRIMARY AND SECONDARY MULTIMEDIA POLLUTANTS
ASSEMBLE MULTIMEDIA ENVIRONMENTAL GOALS (MEGS)
PROJECT NO2 ENVIRONMENTAL GOALS
IMPACT CRITERIA STANDARDS PROJECTIONS
JUSTIFY AND UPDATE MEGS
UPDATE NO2 GOALS
DEFINE SAMPLING/ ANALYSIS REQUIREMENTS
CONDUCT FIELD TESTS, PERFORM CHEMICAL/ BIOASSAY ANALYSES
BASELINE AND CONTROLLED EMISSIONS DATA
DEVELOP METHODS TO COMPARE EFFLUENT CONCENTRATIONS TO MEGS FOR IMPACT EVALUATION
ASSEMBLE POLLUTANT DISPERSION/DILUTION FACTOR MODELS
OUTLINE PROCEDURES FOR RAPID SCREENING SITE EVALUATION
MODEL FORMAT DEVELOPMENT SAM IA SAM IB SAM I SAM II
COMPILE NOx CONTROL PROCESS BACKGROUND
EVALUATE INCREMENTAL EMISSIONS DATA WITH NOx CONTROLS
PRELIMINARY SOURCE/ CONTROL/POLLUTANT PRIORITIES
DEVELOP PROCESS ENGINEERING/EA METHODS
COMPILE DETAILED SOURCE/ CONTROL PROCESS DATA
CONDUCT DETAILED PROCESS STUDY FOR UTILITY BOILERS INDUSTRIAL BOILERS GAS TURBINES RESIDENTIAL HEATING IC ENGINES INDUSTRIAL PROCESS ADVANCED COMBUSTION
ENVIRONMENTAL ASSESSMENT OF COMBUSTION SOURCES AND NOx CONTROLS
DEVELOP PRELIMINARY MODEL FOR ENVIRONMENTAL ALTERNATIVE ANALYSES
SCREEN CONTROL REQUIREMENTS FOR ATTAINING/MAINTAINING AIR QUALITY
SELECT AND ADAPT REACTIVE AIR QUALITY MODEL
PROJECT SOURCE GROWTH AND AMBIENT STANDARDS
ASSESS CONTROL NEEDS FOR VARIOUS REGULATORY REQUIREMENTS
MOST EFFECTIVE CONTROL OPTIONS
A 20210

Figure P-1. NO_x EA approach.

potential for effective NO_x control, to be used in the current ongoing detailed evaluation.

This report presents the assessment of combustion modification NO_x controls for the first source category to be treated, utility boilers. Other environmental assessment reports documented are:

- Environmental Assessment of Industrial Boiler Combustion Modification NO_x Controls (Reference P-2)
- Environmental Assessment of Combustion Modification Controls for Stationary Gas Turbines (Reference P-3)
- Environmental Assessment of Combustion Modification Controls for Stationary Internal Combustion Engines (Reference P-4)
- Environmental Assessment of Combustion Modification Controls for Residential and Commercial Heating Systems (Reference P-5)

Other NO_x EA Program reports and program highlights are documented in Reference P-6.

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TABLE OF CONTENTS

Section — Page

1 EXECUTIVE SUMMARY 1-1

1.1 Introduction 1-1
1.2 Approach 1-3
1.3 Control Effectiveness 1-4
1.4 Energy Impact 1-8
1.5 Process Impact 1-9
1.6 Cost Impact 1-14
1.7 Environmental Impact 1-20
1.8 Conclusions 1-24
1.9 Recommendations 1-28

2 INTRODUCTION 2-1

2.1 Background 2-1
2.2 Role of Utility Boilers 2-3
2.3 Objective of this Report 2-5
2.4 Organization of this Report 2-5

3 SOURCE CHARACTERIZATION 3-1

3.1 Coal-Fired Boilers 3-2

3.1.1 Equipment Types 3-3
3.1.2 Coal Consumption 3-18
3.1.3 Utility Boiler Combustion Process and Effluent Streams 3-24
3.1.4 NO_x Emissions Inventory 3-28
3.1.5 Emission Control Devices 3-31

3.2 Oil-Fired Boilers 3-34

3.2.1 Typical Oil-Fired Boilers 3-35
3.2.2 Oil-Consumption 3-36
3.2.3 NO_x Emissions Inventory 3-38

3.3 Gas-Fired Boilers 3-40

3.3.1 Typical Gas-Fired Boilers 3-42
3.3.2 Natural Gas Consumption 3-42
3.3.3 NO_x Emissions Inventory 3-45

4 OVERVIEW OF NO_x CONTROL TECHNOLOGY 4-1

4.1 General Concepts on NO_x Formation and Control . . 4-1

4.1.1 Thermal NO_x 4-1
4.1.2 Fuel NO_x 4-4
4.1.3 Summary of Process Modification Concepts 4-12

TABLE OF CONTENTS (Continued)

Section Page

4.2 State-of-the-Art Controls 4-13

4.2.1 Low Excess Air (LEA) 4-23
4.2.2 Off Stoichiometric Combustion (OSC) 4-24

4.2.3 Low NO_x Burners (LNB) 4-27
4.2.4 Flue Gas Recirculation (FGR) 4-32
4.2.5 Reduced Firing Rate 4-33
4.2.6 Combination of Controls 4-34

4.3 Advanced Controls 4-34

4.3.1 Advanced Burner/Furnace Designs 4-36
4.3.2 Ammonia Injection 4-38

4.4 Minor Emphasis Controls 4-46

4.4.1 Reduced Air Preheat 4-46
4.4.2 Water Injection 4-47
4.4.3 Flue Gas Treatment 4-48

5 NO_x CONTROL CHARACTERIZATION: EMISSION CORRELATION . . 5-1

5.1 Previous NO_x Modeling Efforts 5-2
5.2 NO_x Emission Correlation Model 5-5

5.2.1 Procedures 5-6
5.2.2 Data Base 5-8

5.3 NO_x Emission Correlation Results 5-17

5.3.1 Tangential Coal-Fired Boilers 5-17
5.3.2 Horizontally Opposed Coal-Fired Boilers 5-23
5.3.3 Single Wall Coal-Fired Boilers 5-27
5.3.4 Horizontally Opposed Oil-Fired Boilers 5-28
5.3.5 Single Wall Oil-Fired Boilers 5-34
5.3.6 Horizontally Opposed Gas-Fired Boilers 5-36
5.3.7 Single Wall Gas-Fired Boilers 5-40

5.4 Summary 5-43

6 NO_x CONTROL CHARACTERIZATION: PROCESS ANALYSIS . . . 6-1

6.1 Process Analysis Procedures 6-1

6.1.1 Assumptions 6-3
6.1.2 Procedures 6-3
6.1.3 Data Sources 6-4

TABLE OF CONTENTS (Continued)

Section Page

6.2 Tangential Coal-Fired Boilers 6-5
6.3 Horizontally Opposed Coal-Fired Boilers 6-19
6.4 Single Wall Coal-Fired Boilers 6-28
6.5 Turbo Furnace Coal-Fired Boilers 6-40
6.6 Tangential Oil-Fired Boilers 6-42
6.7 Horizontally Opposed Oil-Fired Boilers 6-51
6.8 Single Wall Oil-Fired Boilers 6-59
6.9 Turbo Furnace Oil-Fired Boilers 6-69
6.10 Tangential Gas-Fired Boilers 6-74
6.11 Horizontally Opposed Gas-Fired Boilers 6-79
6.12 Single Wall Gas-Fired Boilers 6-84
6.13 Turbo Furnace Gas-Fired Boilers 6-91
6.14 Summary of Process Analyses 6-97

6.14.1 Coal-Fired Boilers 6-97
6.14.2 Oil-Fired Boilers 6-105
6.14.3 Gas-Fired Boilers 6-111

7 COST OF COMBUSTION MODIFICATION CONTROLS 7-1

7.1 Background 7-2
7.2 Cost Analysis Procedures 7-10
7.3 Retrofit Control Costs 7-16
7.3.1 Selection of Representative Boilers. 7-17
7.3.2 Retrofit Design Analysis 7-18
7.3.3 Annualized Retrofit Control Costs. 7-31

7.4 Control Costs for NSPS Boilers 7-46

8 ENVIRONMENTAL ASSESSMENT 8-1

8.1 Environmental Impact 8-1

8.1.1 Carbon Monoxide Emissions 8-2
8.1.2 Hydrocarbon Emissions 8-5
8.1.3 Particulate Emissions 8-6
8.1.4 Trace Metals 8-7
8.1.5 Sulfate Emissions 8-16
8.1.6 Organic Emissions 8-27
8.1.7 Source Analysis Model 8-29
8.1.8 Evaluation and Summary 8-35

8.2 Energy Impact 8-39
8.3 Process Impacts 8-40

8.3.1 Efficiency 8-40
8.3.2 Corrosion 8-40
8.3.3 Slagging and Fouling 8-41
8.3.4 Derating 8-41

TABLE OF CONTENTS (Concluded)

Section Page

8.3.5 Steam and Tube Temperatures 8-41
8.3.6 Flame Instability and Vibrations 8-42
8.3.7 Particulates 8-42
8.3.8 Auxiliary Equipment 8-42
8.3.9 Other Operational Impacts 8-43

8.3.10 Maintenance 8-43
8.3.11 Concluding Remarks 8-43

8.4 Economic Impact 8-43

8.4.1 Retrofit Control Costs 8-44
8.4.2 Control Costs for New Units 8-47
8.4.3 Cost Effectiveness of Controls 8-47
8.4.4 Concluding Remarks 8-49

8.5 Effectiveness of NO_x Controls 8-49

8.5.1 Coal-Fired Boilers 8-49
8.5.2 Oil-Fired Boilers 8-50
8.5.3 Gas-Fired Boilers 8-52

8.6 Conclusions and Recommendations 8-52

8.6.1 Conclusions 8-52
8.6.2 Recommendations 8-55

LIST OF ILLUSTRATIONS

Figure		Page
1-1	Distribution of Stationary Anthropogenic NO_x Emissions for the Year 1977 (Controlled NO_x Levels) . .	1-2
1-2	NO_x Control Development for Coal-Fired Boilers	1-7
2-1	Distribution of Stationary Anthropogenic NO_x Emissions for the Year 1974 (Stationary Fuel Combustion: Controlled NO_x Levels)	2-4
3-1	Typical Tangential Fired Boiler	3-8
3-2	Typical Front Wall Fired Boiler	3-11
3-3	Typical Opposed Wall Fired Boiler	3-12
3-4	Typical Turbo Furnace Fired Boiler	3-13
3-5	Typical Cyclone Fired Boiler	3-17
3-6	Coal-Fired Utility Boiler Combustion Process Flow Diagram	3-25
3-7	Size Comparison Between Coal- and Gas-Fired Steam Generators of the same rating	3-49
4-1	Nitrogen and Sulfur Content of U.S. Coal Reserves . . .	4-6
4-2	Conversion of Fuel N in Practical Combustors	4-8
4-3	Possible Fate of Fuel Nitrogen Contained in Coal Particles During Combustion	4-9
4-4	Conversion of Nitrogen in Coal to NO_x	4-11
4-5	Typical Arrangements for (a) Burners Out of Service, (b) Overfire Air, and (c) Flue Gas Recirculation . . .	4-26
4-6	Effect of Temperature on NO Reduction with Ammonia Injection	4-40
4-7	Nitric Oxide Reductions and Ammonia Carryover with Ammonia Injection at 2 Percent Excess Oxygen	4-41
4-8	Effect of Initial Nitric Oxide Concentrations on NO Reduction with Ammonia Injection	4-43
4-9	Performance of Thermal De-NO_x Systems in Commercial Applications	4-44

LIST OF ILLUSTRATIONS (Continued)

Figure		Page
5-1	Effect of Surface Heat Release Rate and Burner Stoichiometry on NO_x from Tangential Coal-Fired Burners	5-20
5-2	Effect of Heat Input and Burner Stoichiometry on NO_x from Tangential Coal-Fired Boilers	5-22
5-3	Effect of FGR and Burner Stoichiometry on NO_x from Horizontally Opposed Coal-Fired Boilers	5-25
5-4	Effect of Heat Input and Burner Stoichiometry on NO_x from Horizontally Opposed Coal-Fired Boilers	5-26
5-5	Effect of Surface Heat Release Rate and Burner Stoichiometry on NO_x from Single Wall Coal-Fired Boilers	5-29
5-6	Effect of Heat Input per Active Burner and Burner Stiochiometry on NO_x from Single Wall Coal-Fired Boilers	5-30
5-7	Effect of Boiler Load and Burner Stoichiometry on NO_x from Horizontally Opposed Oil-Fired Boilers	5-32
5-8	Effect of Burner Variables on NO_x from Horizontally Opposed Oil-Fired Boilers	5-33
5-9	Effect of Volumetric Heat Release Rate and Burner Stoichiometry on NO_x from Single Wall Oil-Fired Boilers	5-35
5-10	Effect of Heat Input and Burner Stoichiometry on NO_x from Single Wall Oil-Fired Boilers	5-37
5-11	Effect of Firing Rate and Burner Stoichiometry on NO_x from Horizontally Opposed Gas-Fired Boilers	5-39
5-12	Effect of Flue Gas Recirculation and Burner Stoichiometry on NO_x from Horizontally Opposed Gas-Fired Boilers . .	5-41
5-13	Effect of Surface Heat Release Rate and Burner Stoichiometry on NO_x from Single Wall Gas-Fired Boilers	5-42
5-14	Effect of Flue Gas Recirculation and Burner Stoichiometry on NO_x from Single Wall Gas-Fired Boilers	5-44
6-1	Heat Absorption Profile for Barry Unit No. 2	6-13
6-2	Heat Absorption Profile for Columbia Unit No. 1	6-14

LIST OF ILLUSTRATIONS (Continued)

Figure		Page
6-3	Heat Absorption Profile for Huntington Canyon Unit No. 2	6-15
6-4	Overall Mass Balance for Barry Unit No. 2 Boiler . . .	6-16
6-5	Comparison of NO_x Emissions and Minimum Excess Oxygen Levels Under Baseline and Low Excess Air Conditions for South Bay Unit No. 4	6-46
6-6	Comparison of Oil Consumption and Stack Gas Temperature Under Baseline and Low Excess Air Conditions for South Bay Unit No. 4	6-47
6-7	NO_x Emissions and Excess Flue Gas Oxygen Requirements of New LEA Burners Retrofitted on South Bay Unit 4	6-49
6-8	Comparison of NO_x Emissions with Normal and Two-BOOS Operation for Encina No. 1	6-60
6-9	Comparison of Excess O_2 for Normal and Two-BOOS Operation for Encina Unit 1	6-62
6-10	NO_x Emissions for Oil Fuel with Seven-Burner Operation for Encina Unit 1	6-65
6-11	Operating Excess O_2 Curve for Encina Unit No. 1 for Oil Fuel with Seven-Burner Operation	6-66
6-12	Characteristic NO_x Emissions on Oil Fuel from South Bay Unit No. 3	6-72
6-13	Comparison of NO_x Emissions and Minimum Excess Oxygen Levels under Baseline and Low Excess Air Conditions for South Bay Unit No. 4	6-77
6-14	Comparison of Gas Consumption and Stack Temperature Under Baseline and Low Excess Air Conditions for South Bay Unit No. 4	6-78
6-15	Comparison of NO_x with Normal and Two-BOOS Operation with Natural Gas Fuel for Encina Unit No. 1	6-85
6-16	Comparison of excess O_2 for Normal and Two-BOOS Operation with Natural Gas Fuel for Encina Unit No. 1	6-87

LIST OF ILLUSTRATIONS (Concluded)

Figure Page

6-17 NO_x Emissions Versus Load for Gas Fuel with Seven-Burner Operation for Encina Unit No. 1 6-88

6-18 Operating Excess O_2 Curve for Natural Gas Fuel with Seven-Burner Operation for Encina Unit No. 1 6-90

6-19 NO_x Emissions for Gas-Fired South Bay Unit No. 3 . . . 6-95

7-1 1975 Capital Cost of OFA on New Tangential Coal-Fired Boilers 7-7

7-2 1975 Capital Cost of OFA on Existing Coal-Fired Boilers 7-7

7-3 Retrofit Overfire Air for Typical Tangential Coal-Fired Boilers 7-22

7-4 Typical Overfire Air Port Arrangement for Tangential Coal-Fired Boilers 7-23

7-5 Typical OFA Duct Detail for Tangential Coal-Fired Boilers 7-24

7-6 Retrofit Overfire Air for Typical Opposed Wall Coal-Fired Boilers 7-28

7-7 Retrofit OFA and FGR for Typical Single Wall Oil- and Gas-Fired Boilers 7-35

8-1 Partitioning of Class I Elements 8-13

8-2 Partitioning of Class II Elements 8-14

8-3 SO_2 Conversion Vs. Excess Oxygen in Coal-Fired Utility Boilers 8-20

8-4 NO_x Control Development for Coal-Fired Boilers 8-51

LIST OF TABLES

Table Page

1-1 Comparisons of Process Variables for a 525 MW Tangential Western Sub-Bituminous Coal-Fired Boiler Operated Under Similar Conditions at Baseline and Low NO_x Modes 1-5

1-2 Boiler/Retrofit Control Combinations Costed 1-15

1-3 Summary of Retrofit Control Costs[a] (1977 Dollars) . . . 1-17

1-4 Projected Control Requirement for Alternate NO_x Emission Levels 1-19

1-5 Analysis Results for a 180 MW Tangential Coal-Fired Utility Boiler: Flue Gas, Inorganics 1-21

1-6 Flue Gas Discharge Severity -- Inorganics: 180 MW Tangential Coal-Fired Utility Boiler 1-25

1-7 Total Weighted Discharge Severity (g/s) -- Inorganics: 180 MW Tangential Coal-Fired Utility Boiler 1-25

1-8 Combustion Modification NO_x Controls: Best Available Control Technology (BACT) and Advanced Technology 1-26

3-1 Summary of Utility and Large Industrial Boiler Characterization 3-4

3-2 Utility Coal Consumptions, (EJ) 3-19

3-3 Properties and Trace Elements of Representative U.S. Coals 3-21

3-4 Utility Coal Consumption by Coal Types, (EJ) 3-22

3-5 Regional Coal Consumption by Equipment Type, (Percent) 3-23

3-6 Combustion Related Effluent Streams from a Utility Boiler 3-27

3-7 Effect of Nonstandard Operating Procedures on the Effluent Streams from a Dry Bottom Pulverized Coal-Fired Boiler 3-28

3-8 Projected Future NO_x Control Levels for Utility Boilers 3-29

3-9 NO_x Emissions from Coal-Fired Utility Boilers, (Gg/yr) 3-30

LIST OF TABLES (Continued)

Table		Page
3-10	Distribution of Regional Uncontrolled NO_x Emissions from Coal-Fired Utility Boilers in 1974, (Percent) . .	3-32
3-11	Average Particulate Collection from Utility Boilers . .	3-33
3-12	Utility Oil Consumption by Equipment Type, (EJ/yr) . .	3-37
3-13	Utility Oil Fuel Consumption by Type, (EJ/yr)	3-38
3-14	Regional Oil Consumption by Equipment Type in 1974, (Percent)	3-39
3-15	NO_x Emissions from Oil-Fired Utility Boilers, (Gg/yr)	3-40
3-16	Regional Uncontrolled NO_x Emissions from Oil-Fired Utility Boilers in 1974, (Percent)	3-41
3-17	Utility Gas Consumption, (EJ/yr)	3-44
3-18	Regional Natural Consumption by Utilities in 1974, (PJ)	3-46
3-19	NO_x Emissions from Gas-Fired Utility Boilers, (Gg/yr)	3-47
3-20	Distribution of Regional Uncontrolled NO_x Emissions from Gas-Fired Utility Boilers in 1974, (Gg/yr)	3-48
4-1	Factors Controlling the Formation of Thermal NO_x . . .	4-5
4-2	Summary of Combustion Process Modification Concepts . .	4-14
4-3	Average NO_x Reduction with Low Excess Air Firing (LEA)	4-15
4-4	Average NO_x Reduction with Burner Out of Service (BOOS)	4-16
4-5	Average NO_x Reduction with Overfire Air (OFA)	4-17
4-6	Average NO_x Reduction with Flue Gas Recirculation (FGR)	4-18
4-7	Average NO_x Reduction with Reduced Firing Rate	4-19
4-8	Average NO_x Reduction with Off Stoichiometric Combustion and Flue Gas Recirculation (OSC and FGR) . .	4-20

LIST OF TABLES (Continued)

Table Page

4-9 Average NO_x Reduction with Reduced Firing Rate and Off Stoichiometric Combustion 4-21

4-10 Average NO_x Reduction with Load Reduction, Off Stoichiometric Combustion and Flue Gas Recirculation 4-22

4-11 Maximum Reported NO_x Reduction with Boiler Load At or Above 80 Percent MCR 4-35

5-1 Field Test Program Data Compiled 5-10

5-2 Individual Test Points Correlated 5-11

5-3 Boiler Design Variables Considered 5-15

5-4 Properties of Fuels Fired 5-18

6-1 Process Variables Investigated 6-2

6-2 Summary of Process Data Sources 6-6

6-3 Comparison of Flow Variables for a 125 MW Tangential Eastern Bituminous Coal-Fired Boiler Operated Under Similar Conditions at Baseline and Low NO_x Conditions 6-9

6-4 Comparisons of Process Variables for a 525 MW Tangential Western Sub-Bituminous Coal-Fired Boiler Operated Under Similar Conditions at Baseline and Low NO_x Modes 6-10

6-5 Comparison of Process Variables for a 430 MW Tangential Western Bituminous Coal-Fired Boiler Operated Under Similar Conditions and Low NO_x Conditions 6-11

6-6 Summary of POM Emissions from Hatfield Unit No. 3 Measured Upstream of ESP 6-22

6-7 Comparison of Performance Specifications on Two Similar Horizontally Opposed Coal-Fired Boilers 6-24

6-8 Comparison of Process Variables for a Horizontally Opposed Coal-Fired Boiler at Baseline and Low NO_x Conditions (Appendix B): Unit A 6-26

6-9 Comparison of Process Variables for a Pre-NSPS Front Wall Coal-Fired Boiler at Baseline and Low NO_x Conditions: Unit B 6-34

LIST OF TABLES (Continued)

Table Page

6-10 Comparison of Sensitivity of NO_x Emissions to Changes in Excess Air Levels with Increasing Burner Heat Liberation Rates: Unit B 6-35

6-11 Comparison of Process Variables for an NSPS Front Wall Coal-Fired Boiler at Baseline and Low NO_x Conditions: Unit C 6-37

6-12 Comparison of South Bay Unit No. 4 Under Baseline and Low NO_x Conditions Under Partial Load 6-43

6-13 Comparison of Moss Landing Unit No. 6 Under Baseline and Low NO_x Conditions Under partial Load . . 6-52

6-14 Burner Out of Service Test Patterns for a Horizontally Opposed Oil-Fired Boiler 6-58

6-15 Comparison of Encina Unit No. 1 Operated Under Baseline Conditions with Two Burners Out of Service 6-63

6-16 Comparison of Encina Unit No. 1 Operated with Two and Three Out of Service 6-68

6-17 Comparison of South Bay Unit No. 3 at Partial Under Baseline and Low NO_x Operation on Oil Fuel Under Partial Load 6-71

6-18 Comparison of South Bay Unit No. 4 Operated Under Baseline and Low NO_x Conditions Under partial Load 6-75

6-19 Comparison of Moss Landing Boiler No. 7 Under Off Stoichiometric Combustion and Combined Off Stoichiometric Combustion and Flue Gas Recirculation (Reference 6-11) 6-81

6-20 Comparison of Gas-Fired Encina Unit No. 1, Operated Under Baseline Conditions and with Two Burners Out of Service 6-89

6-21 Comparison of Gas-Fired Encina Unit No. 1, Operated with Two and Three Burners Out of Service Prior to Overhaul 6-92

6-22 Comparison of Gas-Fired South Bay Unit No. 3 Under Baseline and Low NO_x Conditions Under Partial Load 6-94

LIST OF TABLES (Continued)

Table Page

6-23 Effect of Low NO_x on Coal-Fired Boilers 6-98

6-24 Effect of Low NO_x Operation on Oil-Fired Boilers . . . 6-106

6-25 Effect of Low NO_x Operation on Gas-Fired Boilers . . . 6-112

7-1 1975 Installed Equipment Costs for Existing PG&E Residual Oil-Fired Utility Boilers. 7-3

7-2 LADWP Estimated Installed 1974 Capital Costs for NO_x Reduction Techniques on Gas- and Oil-Fired Utility Boilers 7-4

7-3 1974 Estimated Investment Costs for Low Excess Air Firing on Existing Boilers Needing Modifications. . . . 7-5

7-4 1975 Differential Operating Costs of OFA on New and Existing Tangential Coal-Fired Utility Boilers. 7-8

7-5 Costs for NO_x Emission Controls on Electric Powerplants Using Gas- and Oil-Fired Steam Generation Equipment, 1977 Dollars 7-9

7-6 Cost Analysis Calculation Algorithm 7-13

7-7 Component Cost Estimate: Retrofit OFA for Tangential Coal-Fired Boiler (1977 Dollars). 7-20

7-8 Installation Cost Estimate: Retrofit OFA for Tangential Coal-Fired Boiler (1977 Dollars) 7-20

7-9 Retrofit OFA for Tangential Coal-Fired Boiler (1977 Dollars). 7-21

7-10 Component Cost Estimate: Retrofit OFA for Opposed Wall Coal-Fired Boiler (1977 Dollars) 7-26

7-11 Installation Cost Estimate: Retrofit OFA for Opposed Wall Coal-Fired Boiler (1977 Dollars) 7-26

7-12 Initial Investment Estimate: Retrofit OFA for Opposed Wall Coal-Fired Boiler (1977 Dollars) 7-27

7-13 Component Estimate: Retrofit Low NO_x Burners for Opposed Wall Coal-Fired Boiler (1977 Dollars) 7-29

7-14 Installation Cost Estimate: Retrofit Low NO_x Burners for Opposed Wall Coal-Fired Boiler (1977 Dollars) . . . 7-29

7-15 Initial Investment Estimate: Retrofit Low NO_x Burners for Opposed Wall Coal-Fired Boiler (1977 Dollars) . . . 7-30

LIST OF TABLES (Continued)

Table | Page
7-16 Component Cost Estimate: Retrofit OFA and FGR for Typical Single Wall Oil- and Gas-Fired Boiler (1977 Dollars). 7-32
7-17 Installation Cost Estimate: Retrofit OFA and FGR for Typical Single Wall Oil- and Gas-Fired Boiler (1977 Dollars). 7-33
7-18 Initial Investment Estimate: Retrofit OFA and FGR for Typical Single Wall Oil- and Gas-Fired Boiler (1977 Dollars). 7-34
7-19 Retrofit Control Cost: Overfire Air for Existing Tangential Coal-Fired Boiler (1977 Dollars) 7-36
7-20 Retrofit Control Cost: Overfire Air from Existing Opposed Wall Coal-Fired Boiler (1977 Dollars) 7-37
7-21 Retrofit Control Cost: Low NO_x Burners for Existing Opposed Wall Coal-Fired Boiler (1977 Dollars) 7-38
7-22 Retrofit Control Cost: Burners Out of Service for Existing Opposed Wall Coal-Fired Boiler (1977 Dollars) 7-39
7-23 Retrofit Control Cost: Burners Out of Service for Existing Single Wall Oil- and Gas-Fired Boiler (1977 Dollars) 7-40
7-24 Retrofit Control Cost: Flue Gas Recirculation and Overfire Air for Existing Single Wall Oil- and Gas-Fired Boiler (1977 Dollars) 7-41
7-25 Summary of Retrofit Control Costs (1977 Dollars). . . . 7-44
7-26 Projected Retrofit Control Requirements for Alternate NO_x Emissions Levels 7-45
8-1 Representative Effects of NO_x Controls on CO Emissions From Utility Boilers 8-4
8-2 Effects of NO_x Controls on Particulate Emissions From Coal-Fired Utility Boilers 8-8
8-3 Effect of NO_x Controls on Emitted Particle Size Distribution From Utility Boilers 8-9
8-4 Trace Element Partitioning -- Bottom Ash/Flyash -- In a Coal-Fired Utility Boiler 8-17

LIST OF TABLES (Concluded)

Table Page

8-5 Trace Species Partitioning With Particle Size -- ESP Inlet of a Coal-Fired Utility Boiler 8-18

8-6 SO_x Emissions From Coal-Fired Utility Boilers 8-21

8-7 Sulfur Species From 180 MW Tangential Coal-Fired Utility Boiler 8-22

8-8 Summary of Process Modifications to Reduce Sulfate Fallout 8-26

8-9 Summary of POM Emissions From Hatfield Unit No. 3 Measured Upstream of ESP 8-28

8-10 Organic Emissions From a 180 MW Coal-Fired Utility Boiler 8-30

8-11 Analysis Results for a 180 MW Tangential Coal-Fired Utility Boiler: Flue Gas, Inorganics 8-32

8-12 Flue Gas Discharge Severity -- Inorganics: 180 MW Tangential Coal-Fired Utility Boiler 8-34

8-13 Total Weighted Discharge Severity (g/s) -- Inorganics: 180 MW Tangential Coal-Fired Utility Boiler 8-34

8-14 Evaluation of Incremental Emissions Due to NO_x Controls Applied to Boilers 8-37

8-15 Boiler/Retrofit Control Combustions Costed 8-45

8-16 Summary of Retrofit Control Costs (1977 Dollars) . . . 8-46

8-17 Projected Control Requirements for Alternate NO_x Emission Levels 8-48

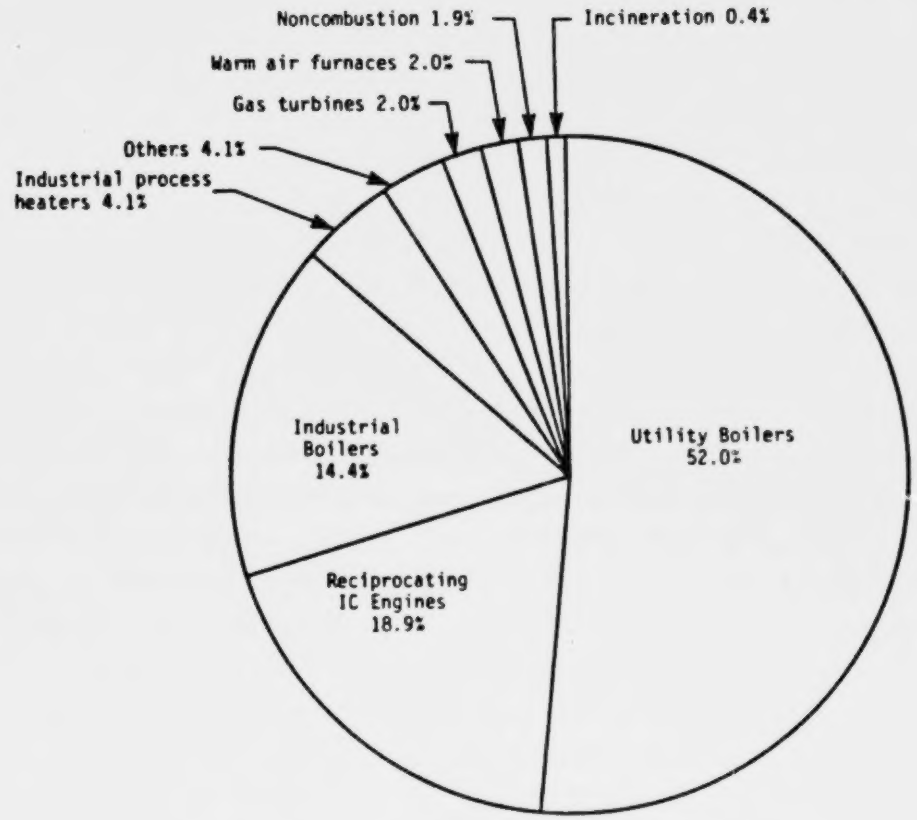
8-18 Combustion Modification NO_x Controls: Best Available Control Technology (BACT) and Advanced Technology . . . 8-53

SECTION 1
EXECUTIVE SUMMARY

1.1 INTRODUCTION

The 1970 Clean Air Act Amendments designated oxides of nitrogen (NO_x) as one of the criteria pollutants requiring regulatory controls to prevent potential widespread adverse health and welfare effects. To attain and maintain ambient air quality standards, the Clean air Act mandated control of new mobile and stationary NO_x sources, each of which emits approximately half of the manmade NO_x nationwide. As shown in Figure 1-1, utility boilers were the origin of approximately 52 percent of all stationary source NO_x emissions for the year 1977. And coal-firing accounted for over 80 percent of those utility boiler emissions (Reference 1-1). The problem of NO_x emissions will continue unless adequate controls are developed (Reference 1-2). The problem will become more severe as impending shortages of oil and gas fuels force conversion to coal, which has the potential for higher NO_x emissions. In fact, the Powerplant and Industrial Fuel Use Act of 1978 (Reference 1-3) and the proposed rules to implement that Act (Reference 1-4) will prohibit all new utility boilers and other major fuel burning installations (MFBI) with an aggregate heat input capacity $\geq$73 MW (250 x 10^6 Btu/hr) from burning oil or natural gas, except under extraordinary circumstances. Furthermore, conversion of existing units to coal may possibly be encouraged through tax incentives.

Since the Clean Air Act, combustion modification control techniques have been developed and implemented that reduce NO_x emissions by a moderate amount (20 to 60 percent) for a variety of source/fuel combinations. In 1971, EPA set Standards of Performance for New Stationary Sources (NSPS) for large steam generators burning gas, oil, and coal (except lignite). Recently, more stringent standards for utility



Total: 10.5 Tg/yr (11.6 x 10^6 tons/yr)

Figure 1-1. Distribution of stationary anthropogenic NO_x emissions the year 1977 (controlled NO_x levels (Reference 1-1).

boilers burning anthracite, bituminous, and subbituminous coals have been promulgated, along with standards for lignite-fired utility boilers (References 1-5 and 1-6).

With more widespread application of combustion modification NO_x controls to meet existing and future control needs, there is a definite need to perform a comprehensive assessment of control effectiveness and environmental impact to give guidance to control developers, users, and control strategists. This report summarizes one effort to provide comprehensive, objective, and realistic evaluations and comparisons of the important aspects of the available combustion NO_x control techniques, using a common and uniform basis for comparison. The objective is to perform an environmental assessment of NO_x combustion techniques for coal-, oil-, and natural gas-fired utility boilers to:

- Determine their effectiveness in reducing NO_x emissions
- Ascertain the effect of their application on boiler performance and identify potential problem areas
- Estimate the economics of their operation
- Determine their impact on the achievement of selected environmental goals, based on a comprehensive analysis from a multimedia consideration
- Identify further research and development and/or testing required to optimize combustion modification techniques and to upgrade their assessments

1.2 APPROACH

The boiler types investigated in this study were tangential, opposed wall, single wall, and turbo furnaces. These four design types encompass the majority of the utility boilers in service in the United States (Reference 1-7). The major NO_x control techniques analyzed in detail were off stoichiometric (staged) combustion (OSC), and low NO_x burners (LNB), flue gas recirculatory (FGR) load reduction (LR) reduced air preheat (RAP), and water injection (WI). Combustion techniques include firing with burners out of service (BOOS), biased burner firing (BBF), and overfire air (OFA) injection above the burner array. Low excess air (LEA) firing was treated both as a NO_x control in this study and as a standard operating procedure. A detailed description of these control techniques as well as a discussion of their fundamental bases in suppressing NO_x formation in the combustion process are given in Section 4.

All available published NO_x control test reports were reviewed for emissions, process performance, and cost data of sufficient detail for this investigation. In addition, several major boiler manufacturers and utility companies graciously supplied new or previously unpublished data from their own test programs. To help fill some of the data gaps, a field test was performed, as part of this study, on a 180 MW electrical output tangential coal-fired boiler.

The basic approach of this investigation was to compare baseline (normal) operating conditions of a boiler with those under controlled NO_x conditions. In addition to comparing NO_x emission levels, the effect of NO_x controls on the incremental emissions of other pollutants was also investigated to help in assessing the overall environmental impact of NO_x controls. To aid in evaluating the process or operational impact of NO_x controls, detailed process variables were compared under baseline and low NO_x conditions. A typical comparison is shown in Table 1-1. These data were then used to analyze changes in process variables due to low NO_x operation and thereby estimate the potential impact of such firing modes on boiler operation and maintenance. To estimate the economic impact of NO_x controls, detailed control costs were calculated using an annualized revenue requirement approach. Finally, to aid in quantifying the overall environmental impact of applying NO_x controls, a source analysis model was applied to the results of the utility boiler field test.

1.3 CONTROL EFFECTIVENESS

Coal-Fired Boilers

The most commonly applied low NO_x technique for coal-fired boilers is staged combustion through overfire air (OFA). Application of burners out of service (BOOS), an alternate staged technique, is limited because it is often accompanied by a 10 to 25 percent load reduction. Average NO_x reductions of 30 to 50 percent (controlled emissions of 215 to 301 ng/J, 0.5 to 0.7 $lb/10^6$ Btu) can be expected with either technique. Load reduction, in itself a moderately effective NO_x control technique, is not considered a viable alternative since utilities generally do not have excess reserve power. Flue gas recirculation (FGR)

TABLE 1-1. COMPARISONS OF PROCESS VARIABLES FOR A 525 MW TANGENTIAL WESTERN SUB-BITUMINOUS COAL-FIRED BOILER OPERATED UNDER SIMILAR CONDITIONS AT BASELINE AND LOW NO_x MODES (Reference 6-3)

Process Variables		Baseline	OFA Operation	Significant Difference
Test Conditions		Full Load	Full Load	
Furnace Conditions		Clean	Clean	
Load	MW	524	523	
Main Steam Flow	kg/s (10^6 lb/hr)	442 (3.51)	444 (3.52)	
Furnace Excess Air	Percent	21.8	26.9	Significant
Th. Air to Fuel Fir. Zone	Percent	118.9	106.0	-12.9
Burner Tilt	Degrees	+1	-5	
OFA Tilt	Degrees	0	0	
Boiler Efficiency	Percent	87.5	87.3	
NO_x[a]	ppm (0% O_2)	520	389	-25%
CO[a]	ppm (0% O_2)	16	10	
C loss in Flyash[a]	Percent	0.03	0.02	
SH Temp	K (^{o}F)	813 (1004)	817 (1011)	
RH Temp	K (^{o}F)	815 (1008)	819 (1015)	
SH Attemp. Spray Flow	kg/s (10^3 lb/hr)	11.0 (87.3)	19.0 (150.8)	+73%
RH Attemp. Spray Flow	kg/s (10^3 lb/hr)	12.0 (95.2)	8.0 (63.5)	-33%
Steam Pressure	MPa (psi)	16.88 (2448)	16.95 (2458)	
FD Fan	Amps	401	434	+8%
ID Fan	Amps	920	1000	+9%
Heat Absorption	Percent of Total			
Economizer	Heat Release	14.4	15.7	
Furnace	Heat Release	27.3	25.2	
Primary Superheater	Heat Release	17.2	17.0	
Secondary Superheater	Heat Release	11.2	13.2	
Reheater	Heat Release	17.2	16.3	
Total Heat Absorbed	Heat Release	87.5	87.3	
Losses	Heat Release	12.5	12.7	

[a] At economizer outlet

has been tested, but found to be a relatively ineffective control, giving only about 15 percent NO_x reduction (Reference 1-9). More recently, low NO_x burners (LNB) have been installed on some units and found to be at least as effective as OFA. The combination of OFA with LNB has resulted in 40 to 60 percent NO_x reductions (controlled emissions of 172 to 258 ng/J, 0.4 to 0.6 $lb/10^6$ Btu).

There has been a steady improvement in combustion modification control technology over recent years. Figure 1-2 conceptually reviews the past, current, and projected development of major controls. As shown, current demonstrated technology (OFA with LNB) is capable of 40 to 60 percent NO_x reductions, easily meeting the current New Source Performance Standard (NSPS) of 215 to 260 ng/J (0.5 to 0.6 $lb/10^6$ Btu), depending on coal type. Ammonia injection, which reduces NO_x by introducing NH_3 as a reducing agent in the post combustion zone, is considered a near-term intermediate control option between current technology and the more distant advanced concepts. It is intermediate from the point of view of control effectiveness and availability. However, ammonia injection has many potential operational and environmental hazards that need to be assessed, as discussed elsewhere, as well as much higher projected costs than either current or the more promising advanced concepts (Reference 1-10). Current R&D programs, such as the EPA advanced low NO_x burner concept (Reference 1-11) and the EPRI primary combustion furnace (Reference 1-12), should result in combustion modification techniques capable of meeting projected future NSPS (1980's) of 86 to 129 ng/J (0.2 to 0.3 $lb/10^6$ Btu).

Oil-Fired Boilers

Commonly applied controls for oil-fired boilers are off stoichiometric combustion through the use of OFA or BOOS, and flue gas recirculation. Typical NO_x reductions using OFA are 20 to 30 percent (controlled emissions of 150 to 172 ng/J, 0.35 to 0.4 ($lb/10^6$ Btu), while BOOS has been slightly more effective giving 20 to 40 percent reductions (controlled levels of 129 to 172 ng/J, 0.3 to 0.4 $lb/10^6$ Btu). Flue gas recirculation also typically gives 20 to 30 percent NO_x reductions, but requires more hardware modifications. The combination of BOOS or OFA with FGR has been most effective, resulting in 30 to 60 percent reductions (controlled emissions of 86 to 172 ng/J, 0.2 to

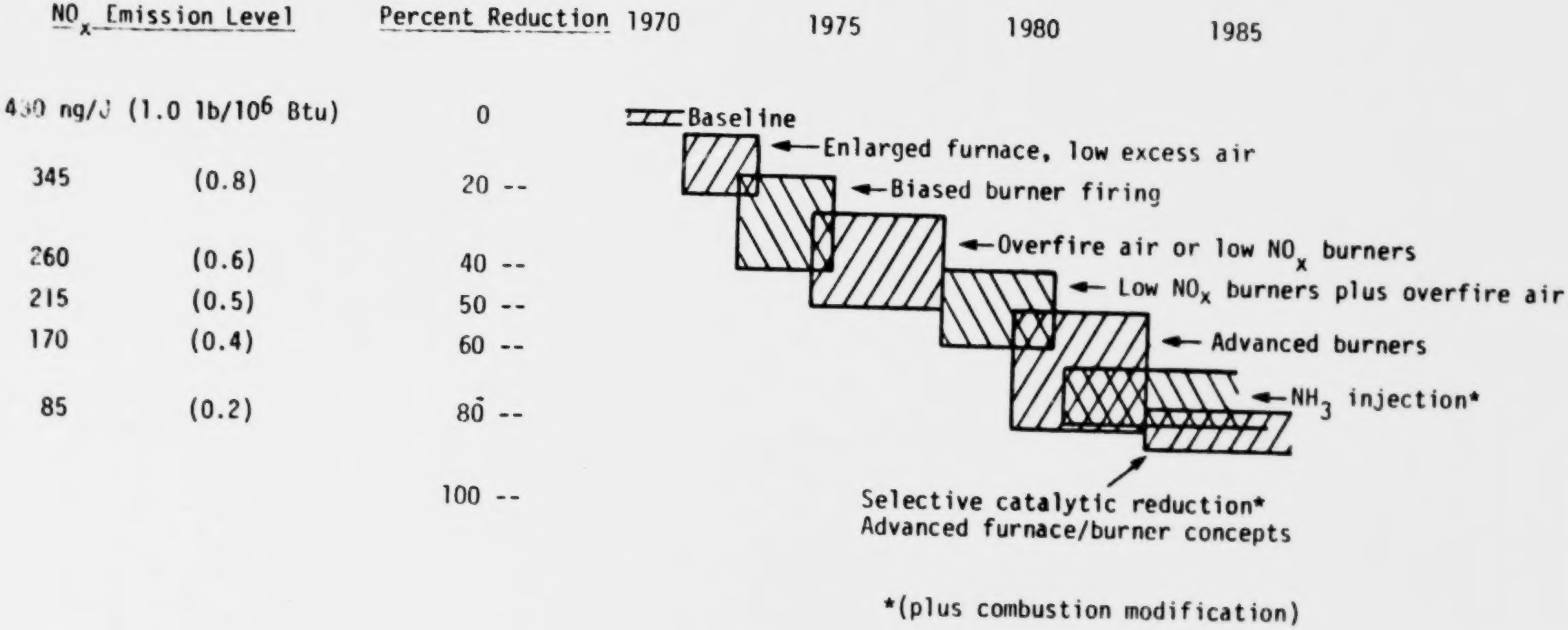


Figure 1-2. NO$_x$ control development for coal-fired boilers.

0.4 lb/10^6 Btu). And recently, one boiler manufacturer has announced the successful retrofit of a low NO_x burner for oil firing, limiting NO_x emissions to below 129 ng/J (0.3 lb/10^6 Btu) (Reference 1-13). Finally, reduced air preheat and water injection, though found effective for oil- and gas-firing, are discounted because of their associated high fuel penalties.

Gas-Fired Boilers

For gas-firing, off stoichiometric combustion through OFA and BOOS, and FGR are again favored. Typical NO_x reductions under either OFA, BOOS, or FGR are 30 to 60 percent (controlled emissions of 86 to 172 ng/J, 0.2 to 0.4 lb/10^6 Btu). The combination of OSC and FGR is capable of 50 to 75 percent reductions (controlled levels of 43 to 129 ng/J, 0.1 to 0.3 lb/10^6 Btu).

1.4 ENERGY IMPACT

A change in energy consumption with application of combustion modification NO_x controls is one of many potential process impacts. Since it can account for up to half of the cost-to-control, energy impact is of paramount importance. The largest potential energy impact of combustion modifications is their effect upon boiler thermal efficiency. Another significant source of energy impact is the change in fan power requirements caused by these controls. Boiler control systems installed for low NO_x operation also increase electricity and instrument air requirements, but the energy impact is usually minimal.

Applying low excess air (LEA) firing not only results in a moderate decrease in NO_x emissions but also an increase in boiler efficiency through reduced sensible heat loss out the stack. For this reason the technique has gained acceptance and has become more a standard operating procedure than a specific NO_x control method in both old and new units.

The other commonly applied combustion modifications, off stoichiometric combustion and flue gas recirculation, can lead to decreases in boiler efficiency when implemented on a retrofit basis. OSC usually increases excess air requirements resulting in decreases in efficiency of up to 0.5 percent. Unburned fuel losses due either to OSC or FGR may cause a decrease in efficiency of up to 0.5 percent. If a substantial increase in reheat steam attemperation is required due to OSC or FGR, cycle efficiency losses of up to 1 percent may occur. Increased fan power requirements due to OSC or FGR will also impact efficiency, resulting in losses of up to 0.3 percent. No significant energy impact is expected with low NO_x burners, either retrofit or new installation.

In summary, the decreases in boiler efficiency (increases in energy consumption) discussed above for the preferred NO_x control techniques (OSC, FGR, and LNB) represent upper estimates when applied on a retrofit basis. These same combustion modifications are not expected to adversely affect unit efficiency when designed in as part of a new unit. This illustrates that, with proper engineering and development, combustion modification NO_x controls can be incorporated into new unit designs with no significant adverse energy impacts.

1.5 PROCESS IMPACT

Coal-Fired Boilers

The major concerns regarding low NO_x operation on coal-fired boilers have been the effects on boiler efficiency, load capacity, furnace wall tube corrosion and slagging, carbon loss, heat absorption profile, and convective section tube and steam temperatures. In most past experiences with off stoichiometric combustion, optimal excess air levels have been comparable to those used under baseline conditions. In these cases the efficiency of the boiler remains unaffected if unburned carbon losses do not increase appreciably. However, in some cases when, due to nonuniform fuel/air distribution or other causes, the excess air requirement increases under staged firing, a significant decrease in efficiency may occur. Efficiency decreases up to 1 percent have been experienced. The same boiler tested at a different time with OSC can show an average increase in efficiency of 1 percent (References 1-14 and 1-15).

Many new boilers now come factory equipped with OFA ports. Older boilers can be retrofitted with OFA ports, or can operate with minimal hardware changes under BOOS firing. BOOS firing is normally accomplished by shutting off one or more pulverizers supplying the upper burner levels. If the other pulverizers cannot handle the extra fuel to maintain the total fuel flow constant, boiler derating will be required. A boiler derating of 10 to 25 percent is not uncommon with BOOS firing.

The possibility of increased corrosion has been a major cause for concern with off stoichiometric combustion. Furnaces fired with certain Eastern U.S. bituminous coals with high sulfur contents may be especially susceptible to corrosion attack under reducing atmospheres. Local reducing atmosphere pockets may exist under staged combustion operation even when burner stoichiometry is slightly over 100 percent. The problem may be further aggravated by slagging as slag generally fuses at lower temperatures under reducing conditions. The sulfur in the molten slag may then readily attack tube walls. Still experience has generally been that no significant acceleration in corrosion rates occurs under staged firing. More recent experience has substantiated this conclusion (Reference 1-16). Nevertheless, the issue cannot be considered resolved until definitive results from long term tests with measurements on actual water wall tubes are available. Such tests are now being sponsored by EPA. Insofar as slagging is concerned, short term tests performed to date indicate no significant increase in slagging or fouling of tubes under staged combustion.

Increased carbon loss in flyash may occur with staged firing if complete burnout of the carbon particles does not occur in the furnace. High carbon loss will result in decreased boiler efficiency and may also cause electrostatic precipitator (ESP) operating problems. Increases in carbon loss vary over a wide range and can be as high as 70 to 130 percent in some cases. However, increased carbon loss is not perceived as one of the major problems associated with staged combustion. If the carbon content in flyash increases to levels where it threatens to impair the operation of dust collection systems, the unburned carbon can usually be easily controlled by increasing the overall excess air level in the furnace. Although this will tend to increase stack heat losses, the decrease in boiler efficiency will be partially compensated for by reduced unburned carbon losses.

Extension of the combustion region to higher elevations in the furnace may result in potential problems with excessive steam and tube temperatures. However, among the numerous short term combustion staging tests conducted, no such problems have been reported. In some tests, where furnace and convective section tube temperatures were measured directly, no significant increase was found. Changes in heat absorption profiles were also found to be minor, thus indicating no need for addition or removal of heat transfer surfaces. Superheater attemperator spray flowrates tripled in one case under OFA operation, but in all cases were well within spray flow capacities of the units (Reference 1-17). Reheater attemperator spray flowrates did not show any increase due to staged operation, thus cycle efficiencies were not affected.

Many new wall fired coal boilers are being fitted with low NO_x burners (LNB). These burners are designed to reduce NO_x levels either alone or in some cases in combination with OFA ports. Using the new burner designs has the advantage of eliminating or decreasing the need for reducing or near reducing conditions near furnace walls. Corrosion problems associated with reducing atmospheres should thus not arise with this system. Although low NO_x burner flames can be expected to be less turbulent and hence longer than flames from normal burners, the combustion zone will probably not extend any farther up the furnace than with staged combustion. Potential changes in heat absorption profile and excessive steam and tube temperatures are, therefore, less likely to occur.

As fuel and air flows are controlled more closely in LNB equipped systems, nonuniform distribution of fuel/air ratios leading to excessive CO generation or high excess air requirements should be eliminated. Boiler efficiencies should, therefore, not be affected. However, the efficiency of one boiler decreased slightly when retrofitted with low NO_x burners (Reference 1-18). The decrease in efficiency was mainly due to the large increase in unburned carbon loss. However, such problems noted in retrofit applications can be avoided in units specifically designed with the low NO_x burners included. Corrosion rates inferred from tests with corrosion coupons showed no significant increase with the new burners (Reference 1-18). Some BOOS tests were carried out on the LNB equipped boiler. A substantial decrease in NO_x emissions resulted, below those already achieved with the new burners alone. However, the boiler was derated by up to 30 percent. Other potential problems noted above as being associated with staged combustion could also arise with this type of firing.

It should be emphasized that the effects of NO_x control, in many cases, will be critically dependent on boiler operating conditions. Still, with proper design of retrofit systems and adequate maintenance programs, low NO_x operation should not result in a substantial increase in operational problems over normal boiler operation. Moreover, when

NO_x controls are designed into new units, potential problems can be anticipated and largely corrected.

Oil-Fired Boilers

The major concerns regarding low NO_x operation on oil-fired boilers are effects on boiler efficiency, load capacity, vibration and flame instability, and steam and tube temperature. Off stoichiometric combustion operation generally increases the minimum excess air requirements of the boiler, which may result in a loss in boiler efficiency. In extreme cases when the boiler is operating close to the limits of its fan capacity, boiler derating may be required. Derates of as much as 15 percent have been required in some cases due to the lack of capability to meet the increased airflow requirements at full load. In addition, under BOOS firing the fuel flow to the active burners must be increased if load is to remain constant. In many cases, it has been necessary to enlarge the burner tips in order to accommodate these increased flows.

Other potential problems attendant with applying off stoichiometric combustion in oil-fired boilers have concerned flame instabilities, boiler vibrations, and excessive convective section tube temperatures. However, in past experience, none of these problems has been significant. Staged combustion does usually result in hazy flames and obscure flame zones. Thus new flame scanners and detectors are often required in retrofit applications. In addition, because staged combustion produces an extended flame zone, flame carryover to the convective section may occasionally occur. However, in one case where intermittant flame carryover occurred, no excessive tube temperatures were recorded.

Similarly, there are a number of potential problems which can occur in retrofit FGR applications. The most common problems, such as FGR fan and duct vibrations, can usually be avoided by good design. Other problems such as flame instability, which can lead to furnace vibrations, are caused by the increased gas velocity at the burner throats. Modifications to the burner geometry and design such as enlarging the throat, altering the burner tips, or adding diffuser plates or flame retainers may then be required.

Another potential problem associated with FGR is high tube and steam temperatures in the convective section. The increased mass velocities which occur with FGR cause the convective heat transfer coefficient to rise. This, coupled with reduced furnace heat absorption, can give rise to high convective section temperatures leading to tube failures, exceeding attemperator spray flow limits, or loss in cycle efficiency due to excessive reheat steam attemperation. Increased mass flowrates in the furnace may also cause furnace pressures to increase beyond safe limits.

The combination of staged combustion and FGR is very effective in reducing NO_x emissions. However, the problems associated with each technique are also combined. Tube and steam temperature problems in the upper furnace are particularly exaggerated, as both combustion staging and FGR tend to increase upper furnace temperatures and convective section heat transfer rates. In addition, boiler efficiencies usually decline slightly with combined staged combustion and FGR firing due to higher EA requirements and greater fan power consumption.

As with coal-fired boilers, before low NO_x techniques are instituted on an oil-fired boiler, it is important to assure that it is in good operating condition. Uniform burner air and fuel flows are essential for optimal NO_x control. Retrofit NO_x control systems must be designed and installed properly to minimize potential adverse effects. Many of the problems experienced in the past can now be avoided because of hindsight and experience. Thus, retrofit systems can now be designed and installed with care to avoid any potential adverse effects.

Gas-Fired Boilers

The effects of low NO_x firing on gas-fired boilers are very similar to those for oil-fired boilers. Usually, there is no distinction between oil- and gas-fired boilers as they are designed to switch from one fuel to the other according to availability. Since boiler design details, NO_x control methods, and the effects of low NO_x operation are similar for gas- and oil-fired units, most of the above discussion of applicable NO_x control measures to oil-fired boilers and potential problems resulting applies. Some effects specific to gas-fired boilers alone are treated briefly in the following.

NO_x emissions oftentimes are difficult to control after switching from oil to gas firing. Residual oil firing tends to foul the furnace due to the oil ash content. Thus, NO_x control measures which have been tested on a clean furnace with gas may be found inadequate after oil firing due to the changed furnace conditions.

Boilers fired with gas usually have higher gas temperatures at the furnace outlet than when fired with oil. The upper furnace and convective section inlet surfaces are thus subject to higher temperatures with gas firing. These temperatures may increase further under staged firing or FGR. Upper furnace and convective section tube failures and excessive steam temperatures are therefore more likely to occur with staged firing and FGR applied to gas-fired boilers. The situation may be aggravated further if switching from gas fuel occurs after an oil burn, as fouling will further reduce furnace absorption and, hence, increase gas temperatures. Excessive tube temperatures may require derating of the system. However, problems with gas firing can be minimized with careful operator attention and paper maintenance procedures.

1.6 COST IMPACT

Estimated costs of applying NO_x controls were calculated using an annualized revenue requirement formulation similar to that described in References 1-19 and 1-20. All cost input data and assumptions employed are discussed in greater detail in Section 7.

Retrofit Control Costs

Representative retrofit control costs were prepared for the boiler/control combinations shown in Table 1-2. For each combination, preliminary engineering designs of the NO_x controls treated were prepared. This design work provided an estimate of the hardware and installation requirements for applying the retrofit controls. Up to date vendor quotes were then obtained to serve as input to the costing algorithm.

It was assumed that the units being retrofitted were relatively new, approximately 5 to 10 years old, with at least 25 years of service remaining. As Table 1-2 shows, overfire air and low NO_x burners were selected as the retrofit control methods for coal-firing. Burners out of service was not necessarily recommended for coal-fired units, but was included to demonstrate the high cost of derating a unit, as is often the case for pulverized coal units. BOOS and OFA combined with FGR were chosen as the preferred techniques for oil- and gas-firing.

TABLE 1-2. BOILER/RETROFIT CONTROL COMBINATIONS COSTED

Boiler/Fuel	MCR[a] MW	NO_x Control
Tangential/coal	225	OFA
Opposed wall/coal	540	OFA
Opposed wall/coal	540	LNB
Opposed wall/coal	540	BOOS
Single wall/oil, gas	90	BOOS
Single wall/oil, gas	90	OFA & FGR

[a] Maximum continuous rating in MW of electrical output.

Estimated costs for applying the treated NO_x controls, in 1977 dollars, are summarized in Table 1-3. The table shows initial capital investment, annualized capital investment with other indirect costs, annualized direct costs, and total annualized cost to control. The table indicates that the preferred combustion modification generally costs between \$0.50 and 0.70/kW-yr to install and operate. One major exception to this is the use of BOOS firing on coal-fired units if derating is required due to insufficient mill capacity. In this instance, the high cost of BOOS implementation reflects the need to purchase makeup power, and to account for lost capacity through a lost capital charge, assuming a 20 percent derate in boiler capacity. For oil- and gas-fired boilers, addition of FGR raises the control cost considerably from \$0.50/kW-yr for OSC alone to \$3.00/kW yr for combined controls.

Control Costs for New Units

Estimating the incremental costs of NO_x controls for NSPS boilers is in some respects an even more difficult task than costing retrofits. Certain modifications on new units, though effective in reducing NO_x emissions, were originally incorporated due to operational considerations rather than from a control viewpoint. For example, the furnace of a typical unit designed to meet 1971 NSPS has been enlarged to reduce slagging potential. But this also reduces NO_x due to the lowered heat release rate. Thus, since the design change would have been implemented even without the anticipated NO_x reduction, the cost of that design modification should not be attributed to NO_x control.

Babcock & Wilcox has estimated the incremental costs of NO_x controls on an NSPS coal-fired boiler (Reference 1-21). The two units used in the comparison were identical except for NO_x controls on the NSPS unit which included:

- Replacing the high turbulence, rapid-mixing cell burner with the limited turbulence dual register (low NO_x) burner
- Increasing the burner zone by spreading the burners vertically to include 22 percent more furnace surface
- Metering and controlling the airflow to each row of burners using a compartmented windbox.

TABLE 1-3. SUMMARY OF RETROFIT CONTROL COSTS[a] (1977 DOLLARS)

Boiler/Fuel Type	Initial Investment ($/kW)	Annualized Indirect Operating Cost ($/kW-yr)	Annualized Direct Operating Cost ($/kW-yr)[b]	Total to Cost Control ($/kW-yr)[b]
Tangential/Coal-Fired				
OFA	0.90	0.21	0.32	0.53
Opposed Wall/Coal-Fired				
OFA	0.62	0.16	0.52	0.69
LNB	2.03	0.34	0.06	0.40
BOOC	0.08	5.34	24.78	30.12
Single Wall/Oil- and Gas-Fired				
BOOS	0.30	0.05	0.44	0.49
FGR/OFA	5.71	1.14	1.91	3.05

[a] Based on assumptions given in Section 7 and cost input parameters listed in Appendix E.

[b] Based on 7000 h operating year. Typical costs only.

[c] Assumes 20 percent derate required.

To provide these changes for NO_x control, the price increase was about \$1.75 to 2.50/kW (1977 dollars). If these costs are annualized they translate to \$0.28 to 0.40/kW-yr.

In addition, Foster Wheeler has performed a detailed design study aimed at identifying the incremental costs of NO_x control included in NSPS units (Reference 1-22). Foster Wheeler looked at these unit designs with the following results:

	Boiler Design	Relative Cost
Unit 1:	Pre-NSPS base design	100
Unit 2:	Enlarged furnace, no active NO_x control	114
Unit 3:	NSPS design; enlarged furnace, new burner design, perforated hood, overfire air, boundary air	115.5

Assuming the cost of a pre-NSPS coal-fired boiler to be about \$100/kW in 1969, or \$180/kW in 1977 construction costs (References 1-23, 1-24, and 1-25), the incremental cost of active NO_x controls (LNB plus OFA) is \$2.70/kW, or about \$0.43/kW-yr annualized. The Foster Wheeler estimate which includes both LNB and OFA, thus agrees quite well with the Babcock & Wilcox estimate, which includes only LNB and associated equipment.

Cost-Effectiveness of Controls

Combustion modifications represent cost-effective, demonstrated means of NO_x control for utility boilers, reducing NO_x emission 20 to 60 percent at relatively low cost, usually less than 1 percent of the cost of electricity. Furthermore, the initial capital cost is usually less than 1 percent of the cost of the boiler. Table 1-4 summarizes projected control requirements for alternative NO_x emission levels. Control requirements are recommended to achieve a given NO_x emission level. These control levels, combined with the cost of control column, complete the cost-effectiveness picture. It is evident that control of new boilers is more cost-effective than retrofitting existing units.

TABLE 1-4. PROJECTED CONTROL REQUIREMENTS FOR ALTERNATE NO$_x$ EMISSION LEVELS

Fuel/NO$_x$ Emission Level: ng/J (lb/10^6 Btu)	Recommended Control Requirement[a]	Cost to Control: \$/kW-yr[b]	
		Retrofit	New Boiler
Coal			
301 (0.7)	OFA[c]	0.50 to 0.70	0.10 to 0.20
258 (0.6)	OFA[c]	0.50 to 0.70	0.10 to 0.20
215 (0.5)	LNB	0.40 to 0.50	0.30 to 0.40
172 (0.4)	OFA + LNB	0.95 to 1.20	0.40 to 0.50
Oil			
129 (0.3)	BOOS	0.50 to 0.60	N/A[d]
86 (0.2)	FGR + OFA	3.00	
Gas			
129 (0.3)	BOOS	0.50 to 0.60	N/A[d]
86 (0.2)	FGR + OFA	3.00	
43 (0.1)	FGR + OFA	3.00	

[a] LEA considered standard operating practice.

[b] Typical installation only; could be significantly higher. 1977 dollars.

[c] As manufacturers acquire more experience with LNB, they are now recommending LNB over OFA.

[d] N/A - Not applicable, no new oil- or gas-fired boilers being sold.

1.7 ENVIRONMENTAL IMPACT

To help quantify the potential change in environmental impact of a utility boiler which switches from baseline to low NO_x firing, a source analysis model (Reference 1-26) was applied to the effluent data from the 180 MW coal-fired utility boiler tested in this study. EPA has been developing a series of source analysis models to define methods of comparing emission data to environmental objectives (Reference 1-27). The model selected for the level of data detail obtained from the utility boiler tests was designed for rapid screening purposes. As such, it includes no treatment of pollutant transport or transformation. Goal comparisons employ threshold effluent stream concentration goals.

For the purposes of screening pollutant emissions data to identify species requiring further study, a Discharge Severity (DS) is defined as follows:

$$DS_i = \frac{\text{Concentration of Pollutant i in Effluent Stream}}{\text{Threshold Effluent Concentration of Pollutant i}}$$

The threshold effluent concentration is the maximum pollutant concentration considered safe for occupational exposure. When DS exceeds unity, more refined chemical analysis may be required to quantify specific compounds present.

To compare waste stream potential hazards, a Total Weighted Discharge Severity is defined as follows:

$$\text{TWDS} = (\Sigma_i \ DS_i) \times \text{Mass Flow Rate},$$

where the Discharge Severity is summed over all species analyzed. The TWDS is an indicator of output of hazardous pollutants and can be used to rank the needs for controls for waste streams. It can also be used as a preliminary measure of how well a pollutant control, say a combustion modification NO_x control, reduces the overall environmental hazard of the source.

The model was applied to the analysis results from the 180 MW unit. Table 1-5 summarizes the boiler outlet flue gas effluent concentrations (ESP outlet for particulates and trace species) for

TABLE 1-5. ANALYSIS RESULTS FOR A 180 MW TANGENTIAL COAL-FIRED UTILITY BOILER: FLUE GAS, INORGANICS

TEST	BASELINE	BIAS (Test 1)	BOOS (Test2)
Heat input (% of baseline)	100	100.9	92.4
Emissions $\frac{\mu g}{m^3}$ dry			
NO_x(ppm @ 3% O_2 dry)	$1.16x10^6$ (490)	$7.35x10^5$ (336)	$6.54x10^5$ (304)
SO_2(ppm @ 3% O_2 dry)	$4.18x10^6$ (1668)	$3.5x10^6$ (1354)	$4.21x10^6$ (1591)
SO_3(ppm @ 3% O_2 dry)	$1.45x10^4$ (3)	$1.32x10^4$ (3)	9580 (3)
CO^x(ppm @ 3% O_2 dry)	$3.07x10^4$ (28.6)	$4.58x10^4$ (35.0)	$3.19x10^4$ (21.7)
CO_2(%)	$2.72x10^8$ (13.9)	$2.82x10^8$ (14.4)	$2.86x10^8$ (14.6)
O_2	(5.2)	(4.7)	(4.4)
Particulate	$6.3x10^5$	$6.7x10^5$	$4.3x10^5$
Antimony	3.9	<2.6	<2.6
Arsenic	95	78	81
Barium	$2.25x10^3$	$1.7x10^3$	$1.5x10^3$
Beryllium	9.0	11	7.3
Bismuth	<53	<56	$2.3x10^2$
Boron	--	--	$8.8x10^2$
Cadmium	2.3	<2.4	<2.1
Chromium	$1.69x10^3$	$4.8x10^2$	$2.4x10^3$
Cobalt	66	75	89
Copper	$2.9x10^2$	$3.4x10^2$	$3.2x10^2$
Iron	$4.5x10^4$	$3.4x10^4$	$3.3x10^4$
Lead	74	86	51
Manganese	$2.4x10^2$	$1.3x10^2$	$1.9x10^2$
Mercury	1.8	3.1	3.5
Molybdenum	$1.5x10^2$	<56	$8.7x10^2$
Nickel	$8.4x10^2$	$1.0x10^3$	$-1.5x10^3$
Selenium	10	8.2	5.1
Tellurium	<4.1	<4.0	<3.7

TABLE 1-5. Concluded

TEST	BASELINE	BIAS (Test 1)	BOOS (Test2)
Thallium	<2.6	<2.7	<2.1
Tin	<6.4	<6.7	<5.1
Titanium	$6.1\text{x}10^3$	$5.7\text{x}10^3$	$3.6\text{x}10^3$
Uranium	<3.9	44	<2.1
Vanadium	$2.6\text{x}10^2$	$2.3\text{x}10^2$	$1.6\text{x}10^2$
Zinc	$4.3\text{x}10^2$	$5.9\text{x}10^2$	$8.4\text{x}10^2$
Zirconium	$1.9\text{x}10^2$	$2.6\text{x}10^2$	$6.8\text{x}10^2$
Chloride	$2.7\text{x}10^2$	$4.1\text{x}10^2$	$8.6\text{x}10^2$
Fluoride	84	$3.5\text{x}10^2$	$1.2\text{x}10^2$
Cyanide	<1.3	0.3	<1.3
Nitrate	<3.9	24	$7.7\text{x}10^2$
Sulfate	$6.5\text{x}10^3$	$3.9\text{x}10^3$	$2.1\text{x}10^3$
Ammonium	<5.3	7.2	$1.4\text{x}10^2$
Coal Analysis			
C%	63.13	63.46	64
H%	4.27	4.24	4.23
O%	7.34	7.97	7.11
N%	1.38	1.13	1.38
S%	2.19	1.75	2.13
H_2O%	2.04	2.34	2.58
Ash%	19.60	19.09	18.49
HHV, J/g	26288	26363	26521
Btu/lb	11302	11334	11402

baseline and low NO_x firing. Two levels of NO_x reduction were tested. Retrofit bias burner firing gave a 32 percent NO_x reduction, and operation with the upper row of nozzles on air only gave a 38 percent NO_x reduction. However, the percent NO_x reduction with bias firing should be tempered somewhat by the fact that there was a slight decrease in fuel nitrogen content for that test. The furnace efficiency either remained constant or increased slightly (due to lower excess air) under low NO_x operation. There was no appreciable increase in carbon-in-flyash with NO_x controls. It should be mentioned that these tests were for short periods, so the long term operability under these low NO_x conditions was not necessarily validated.

Unfortunately, due to limited coal supplies, the coal sulfur contents were not constant throughout the test program, as noted in Table 1-5. Nevertheless, the data do indicate that SO_2 emissions are not significantly affected by low NO_x firing. This is certainly the case when comparing the BOOS test with baseline. And the drop in SO_2 emissions with the bias test can be attributed to the decrease in fuel sulfur content, since 98 percent of the sulfur introduced into a utility appears in flue gas as an oxide (Reference 1-28).

Comparing particulate emissions under bias firing with those under baseline would indicate that low NO_x firing would have no significant effect. However the observed decrease in particulate emissions under BOOS firing cannot be fully explained by the lower fuel ash content or the lower boiler firing rate. Nonetheless, the bias test when reinforced with data from several other field test programs do show that particulate emissions and particle size distribution are relatively unaffected by low NO_x firing.

For the majority of elements listed in Table 1-5, the changes in emission rates between baseline operation and low NO_x firing were within the accuracy of the analysis and are not judged to be significant. Notable exceptions are the leachable nitrates and ammonium compounds. Here it is possible that local fuel rich conditions under low NO_x operation suppress reduced nitrogen compound oxidation normal to baseline operation. Organic species analyses were inconclusive, though total organic emissions increased with low NO_x firing. Reference 1-1 presents the analysis results for the other waste streams -- cyclone ash, ESP ash, and bottom ash slurry. Table 1-6 lists the DS values for those inorganic species or compounds where DS ≥ 1. It is evident that the gaseous pollutants, particularly SO_2 and NO_x, dominate the potential toxicity of the flue gas stream. Of the trace metals, arsenic shows the highest DS, but none of the metals show any large change under low NO_x conditions. As may be expected, SO_3 decreased under low NO_x operation and reduced N compounds increased.

The total weighted discharge severity for the inorganic component of four waste streams of the boiler are compared in Table 1-7. Clearly the flue gas stream dominates the TWDS with the solid streams 3 orders of magnitude potentially less toxic, according to the model. With low NO_x firing, the flue gas stream TWDS is reduced, primarily due to the decrease in NO_x concentration. The TWDS's for the other waste streams either decreased or were constant when going to low NO_x firing. As mentioned earlier, more data are needed for waste stream organic composition before the discharge severity for organic compounds, relative to inorganics, can be estimated.

From the application of the source analysis model to the admittedly sparse data base of a few short tests on a single coal-fired boiler, the results indicate that NO_x controls are generally beneficial, reducing the overall adverse environmental impact of waste streams. These results, along with the general indications from other reported tests, tend to confirm that combustion modification NO_x controls are environmentally sound, though work remains to confirm and correct any potential adverse environmental impacts from incremental emissions.

1.8 CONCLUSIONS

Modifying the combustion process conditions is currently the most cost-effective and best demonstrated method of effecting 20 to 60 percent reductions in NO_x emissions from utility boilers. Table 1-8 summarizes the capabilities of combustion modification NO_x controls. The methods in the current control technology and advanced technology categories are listed in preference of application. They were selected based on an assessment of their effectiveness, operational, energy, cost, and environmental impact, and commercial availability or R&D status.

In the current technology category, low NO_x burners or off stoichiometric combustion through overfire air addition (OFA) is the

TABLE 1-6. FLUE GAS DISCHARGE SEVERITY -- INORGANICS: 180 MW TANGENTIAL COAL-FIRED UTILITY BOILER

	BASELINE	BIAS	BOOS
NO_x	129	84	73
SO_2	322	269	324
SO_3	15	13	9.6
CO	0.77	1.1	0.80
CO_2	30	31	32
Be	4.5	5.5	3.6
Ba	4.5	3.4	3.0
As	48	39	41
Ti	1	0.95	0.60
N (Mainly NH_4)	0.07	0.22	6.1
SO_4	6.5	3.9	2.1
Chlorides	0.68	1	2.1

TABLE 1-7. TOTAL WEIGHTED DISCHARGE SEVERITY (g/s) -- INORGANICS: 180 MW TANGENTIAL COAL-FIRED UTILITY BOILER

	BASELINE	BIAS	BOOS
Flue Gas	4.3×10^7	3.5×10^7	3.7×10^7
Cyclone Ash	1.9×10^4	1.6×10^4	1.6×10^4
ESP Ash	6.1×10^3	6.1×10^3	5.1×10^3
Bottom Ash Slurry	5.7×10^4	5.3×10^4	4.2×10^4
Total	4.3×10^7	3.5×10^7	3.7×10^7

TABLE 1-8. COMBUSTION MODIFICATION NO_x CONTROLS: BEST AVAILABLE CONTROL TECHNOLOGY (BACT) AND ADVANCED TECHNOLOGY

	Fuel	Control Technique	NO_x Control Level, ng/J	(lb/10^6 Btu)
BACT	Coal	Overfire air[a]	258	(0.6)
		Low NO_x burners	215	(0.5)
		Low NO_x burners plus overfire air	172	(0.4)
	Oil	Burners out of service or overfire air	129	(0.3)
		Flue gas recirculation plus overfire air	86	(0.2)
	Gas	Burners out of service or overfire air	129	(0.3)
		Flue gas recirculation plus overfire air	43	(0.1)
Advanced Technology	Coal	Ammonia injection (1983)[b] (combined with BACT combustion modifications)	129	(0.3)
		Advanced low NO_x burners (1985)	86	(0.2)
		Advanced burner/furnace concepts (1985)	60	(0.15)
	Oil	Ammonia injection (1983) (combined with BACT combustion modifications)	43	(0.1)

[a] As manufacturers acquire more experience with LNB, they are now recommending LNB over OFA.

[b] Estimated date of commercial availability of demonstrated technology.

preferred technique for retrofit application to coal-fired units, with the use of new low NO_x burners, or new burners in combination with OFA, favored for new units. While current technology can achieve 172 ng/J (0.4 lb/10^6 Btu) for coal-firing, Table 1-8 indicates that advanced techniques have the potential of reducing NO_x to 60 ng/J (0.15 lb/10^6 Btu). However, ammonia injection, advanced low NO_x burners, and advanced burner/furnace concepts are several years away. Current technology for oil- and gas-fired boilers can reduce NO_x to the relatively low levels of 86 to 43 ng/J (0.2 to 0.1 lb/10^6 Btu), respectively.

Potential problems with the use of conventional combustion modifications have concerned possible adverse effects on boiler efficiency, load capacity, furnace wall tube corrosion and slagging, fouling, carbon loss, steam and tube temperatures, and flame stability and vibration. However, recent field experience has shown that adverse effects can be minimized to acceptable levels with proper care in design for retrofit applications, and largely eliminated in new unit designs.

Another area of concern with combustion modification NO_x controls is possible increase in incremental emissions of other pollutants to the environment. Recent test data with conventional techniques seem to indicate that low NO_x firing has negligible effects on emissions of most pollutants other than NO_x. Low NO_x firing does indeed lower the overall potential environment impact of the source. However, there are areas of continued concern, such as possible increased organic emissions. More extensive field testing will be required to identify and better quantify these emissions, and compare these results with developing information in the health effects area.

Finally, conventional combustion modifications are indeed cost-effective means of control for NO_x, raising the cost of electricity less than 1 percent in most cases. Furthermore, the initial capital investment required should also only be of the order of 1 percent or less of the installed cost of a boiler. With the exception of post combustion NH_3 injection, advanced techniques (such as advanced low NO_x burners and advanced burner/furnace concepts) have projected costs in the same range as conventional combustion modifications. Therefore, preferred current and projected combustion modification techniques are not expected to have any significant adverse economic impact.

1.9 RECOMMENDATIONS

Preferred conventional combustion modifications are indeed recommended for reducing NO_x emissions from utility boilers, with minimal adverse environmental, operational, and cost impacts. However, longterm testing and monitoring of field applications/demonstrations should be continued. Although the issue of possible increased corrosion with staged combustion has been largely resolved in short-term tests, long-term corrosion testing, as under current EPA programs, should be completed to definitively establish that low NO_x firing does not have any adverse effects. Boiler efficiency should be closely monitored during field applications to give guidance to control developers on minimizing or eliminating efficiency losses. The current data base indicates that efficiency losses of zero to 0.5 percent are possible. The exact number is of significance; for example, a 0.25 percent loss in efficiency can translate to one-third of the annualized cost to control.

Finally, the data gaps on the effect of NO_x controls on incremental emissions are just now beginning to be addressed. Field testing, with special emphasis on incremental emissions such as trace metals and organics, on representative utility boiler/control applications should continue.

Research and development efforts on new combustion modification technology, such as advanced staged combustion, low NO_x burners and burner/furnace concepts, should continue; they have the potential of further NO_x reduction capabilities with minimal adverse impacts.

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SECTION 2
INTRODUCTION

This report assesses the operational, economic, and environmental impacts from applying combustion modification NO_x controls to utility and large industrial boilers. With more NO_x controls being implemented in the field and expanded control development anticipated for the future, there is currently a need to: (1) ensure that the current and emerging control techniques are technically and environmentally sound, and compatible with efficient and economical operation of systems to which they are applied, and (2) ensure that the scope and timing of the new control development program are adequate to allow stationary sources of NO_x to comply with potential air quality standards. The NO_x EA program addresses these needs by (1) identifying the incremental multimedia environmental impact of combustion modification controls, and (2) identifying the most cost-effective source/control combinations to achieve ambient NO_2 standards.

2.1 BACKGROUND

The 1970 Clean Air Act Amendments designated oxides of nitrogen (NO_x) as one of the criteria pollutants requiring regulatory controls to prevent potential widespread adverse health and welfare effects. Accordingly, in 1971, EPA set a primary and secondary National Ambient Air Quality Standard (NAAQS) for NO_2 of 100 $\mu g/m^3$ (annual average). To attain and maintain the standard, the Clean Air Act mandated control of new mobile and stationary NO_x sources, each of which emits approximately half of the manmade NO_x nationwide. Emissions from light duty vehicles (the most significant mobile source) were to be reduced by 90 percent to a level of 0.25 g NO_2/km (0.4 g/mile) by 1976. Stationary sources were to be regulated by EPA New Source Performance Standards (NSPS), which are set as control technology becomes available. Additional standards required to attain air quality in the Air Quality Control Regions (AQCR's) could be set for new or existing sources through the State Implementation Plans (SIPs).

Since the Clean Air Act, techniques have been developed and implemented that reduce NO_x emissions by a moderate amount (30 to 60 percent) for a variety of source/fuel combinations. In 1971, EPA set NSPS for large steam generators burning gas, oil, and coal (except lignite). Recently, more stringent standards for utility boilers burning all gaseous, liquid, and solid fuels have been promulgated. In addition, NSPS have been promulgated for stationary gas turbines and are currently being considered for stationary internal combustion engines and intermediate size (industrial) steam generators. Local standards also have seen set, primarily for new and existing large steam generators and gas turbines, as parts of State Implementation Plans in several areas with NO_x problems. This regulatory activity has resulted in reducing NO_x emissions from stationary sources by 30 to 60 percent. The number of controlled sources is increasing as new units are installed with factory equipped NO_x controls.

Emissions have been reduced comparably for light duty vehicles. Although the goal of 90 percent reduction (0.25 g NO_2/km) by 1976 has not been achieved, emissions were reduced by about 25 percent (1.9 g/km) for the 1974 to 1976 model years and in 1979 were reduced to 50 percent to 1.25 g/km. Achieving the 0.25 g/km goal has been deferred indefinitely because of technical difficulties and fuel penalties. Initially, the 1974 Energy Supply and Environmental Coordination Act deferred compliance to 1978. Recently, the Clean Air Act Amendments of 1977 abolished the 0.25 g/km goal and replaced it with an emission level of 0.62 g/km (1 g/mile) for the 1981 model year and beyond. However, the EPA Administrator is required to review the 0.25 g/km goal, considering the cost and technical capabilities, as well as the need of such a standard to protect public health or welfare. A report to the Congress is due July 1980.

Because the mobile source emission regulations have been relaxed, stationary source NO_x control has become more important for maintaining air quality. Several air quality planning studies have evaluated the need for stationary source NO_x control in the 1980's and 1990's in view of recent developments (References 2-1 through 2-9). These studies all conclude that relaxing mobile standards, coupled with the continuing growth rate of stationary sources, will require more stringent stationary source controls than current and impending NSPS provide. This conclusion has been reinforced by projected increases in the use of coal in stationary sources. The studies also conclude that the most cost-effective way to achieve these reductions is by using combustion modification NO_x controls in new sources.

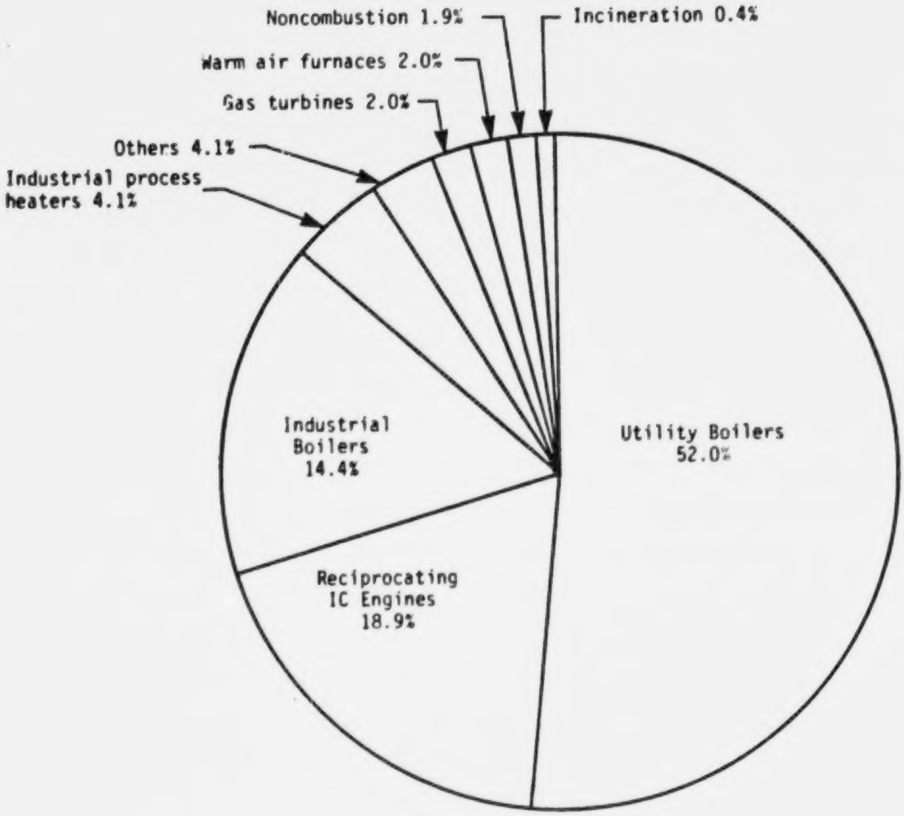
It is also possible that separate NO_x control requirements will be needed to attain and/or maintain additional NO_2 related standards. Recent data on the health effects of NO_2 suggest that the current NAAQS should be supplemented by limiting short term exposure (References 2-4 and 2-10 through 2-12). In fact, the Clean Air Act Amendments of 1977 require EPA to set a short term NO_2 standard for a period not to exceed 3 hours, unless it can be shown that such a standard is not needed. EPA will probably propose a short term standard in 1980 when update of the NO_2 air quality criteria document (Reference 2-13) is completed (References 2-14 and 2-15).

EPA is continuing to evaluate the long range need for additional NO_x regulation as part of strategies to control oxidants or pollutants for which NO_x is a precursor, e.g., nitrates, nitrosamines, and acid rain (References 2-4, 208, 2-10, and 2-14 through 2-18). These regulations could be source emission controls or additional ambient air quality standards. In either case, additional stationary source control technology could be required to assure compliance.

In summary, since the Clean Air Act, near term trends in NO_x control are toward reducing stationary source emissions by a moderate amount, hardware modifications in existing units or new units of conventional design will be stressed. For the far term, air quality projections show that more stringent controls than originally anticipated will be needed. To meet these standards, the preferred approach is to control new sources by using low NO_x redesigns.

2.2 ROLE OF UTILITY BOILERS

Utility boilers produce the largest contribution of NO_x emissions from stationary sources in the U.S. In fact, Figure 2-1 shows that utility boilers were the origin of 52 percent of all stationary anthropogenic NO_x emissions for the year 1977 (Reference 2-19). The problem of NO_x emissions will continue unless adequate controls are developed (Reference 2-20). The problem will become more severe as impending shortages of oil and gas fuels force conversion to coal, which has the potential for higher NO_x emissions. In fact, the Powerplant and Industrial Fuel Use Act of 1978 (Reference 2-22)



Total: 10.5 Tg/yr (11.6 x 10^6 tons/yr)

Figure 2-1. Distribution of stationary anthropogenic NO_x emissions for the year 1974 (stationary fuel combustion: controlled NO_x levels).

will prohibit all new utility boilers and other major fuel burning installations with an aggregate heat input capacity $\geq$73 MW (250 x 10^6 Btu/hr) from burning oil or natural gas, except under extraordinary circumstances. Furthermore, conversion of existing units to coal may possibly be encouraged through tax incentives.

Given this background and their potential for NO_x control, utility boilers were chosen as the first source category to be treated under the NO_x EA program. The "Preliminary Environmental Assessment of Combustion Modification Techniques" (Reference 2-8) concluded that modifying combustion process conditions is the most effective and widely used technique for achieving 20 to 70 percent reduction in oxides of nitrogen. Nearly all current NO_x control applications use combustion modifications. Other approaches, such as treating postcombustion flue gas, are being evaluated in depth elsewhere (Reference 2-23) for potential future use.

2.3 OBJECTIVE OF THIS REPORT

This report provides comprehensive, objective, and realistic evaluations and comparisons of the important aspects of the available combustion NO_x control techniques, using a common and uniform basis for comparison. The objective is to perform an environmental assessment of NO_x combustion modification techniques for utility and large industrial boilers to:

- Determine their impact on the achievement of selected environmental goals, based on a comprehensive analysis from a multimedia consideration
- Ascertain the effect of their application on boiler performance and identify potential problem areas
- Estimate the economics of their operation
- Estimate the limits of control achievable by combustion modification
- Identify further research and development and/or testing required to optimize combustion modification techniques and to upgrade their assessments

2.4 ORGANIZATION OF THIS REPORT

Evaluating the effectiveness and impacts of NO_x combustion controls applied to utility and large industrial boilers requires assessing their effects on both controlled source performance, especially as translated into changes in operating costs and energy consumption, and on incremental emissions of other pollutants as well as NO_x. To perform such an evaluation, it is necessary to:

- Characterize the source category with regards to equipment and emissions, including projected control requirements (Section 3)
- Identify current and potential NO_x control techniques available for implementation (Section 4)
- Identify key combustion parameters affecting NO_x formation by correlating NO_x emissions with these parameters, thereby assessing the basis and effectiveness of control techniques which modify these parameters (Section 5)
- Relate the application of preferred (major) NO_x controls to demonstrated or expected impacts on controlled source operations and performance (Section 6)
- Estimate the capital and operating costs, including energy impacts of implementing NO_x control (Section 7)
- Evaluate the environmental impact of NO_x controls through the analysis of incremental emissions (Section 8)

Section 8 also summarizes the effectiveness of NO_x controls, their boiler operation/maintenance impact, and their economic impact. It concludes with control technology and R&D recommendations.

Volume II of this report (Reference 2-24), printed under separate cover, presents supporting data not listed in the present volume.

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SECTION 3
SOURCE CHARACTERIZATION

This section presents a general characterization of the utility boiler NO_x source category to aid in the process engineering and evaluation of controls that follow in the subsequent sections of this report. Utility boilers were categorized by equipment design and fuel fired according to characteristics which affect the formation and/or control of NO_x. The Preliminary Environmental Assessment of Combustion Modification Techniques (PEAR, Reference 3-1) concluded that the number of equipment/fuel classifications is too large to treat comprehensively at the same level of detail. Accordingly, the PEAR completed a preliminary prioritization of these classifications based on the quantification of source emissions and the evaluation of the potential applications of NO_x control for various equipment/fuel types. For example, there are a number of equipment designs in the field which are no longer being manufactured. Since the bulk of these sources are scheduled to be retired and have not been retrofitted with NO_x controls, they were accorded lesser priority in this study.

The PEAR (Reference 3-1) divided utility boilers into major design types (tangential, single wall, and opposed wall) likely to be extensively controlled for NO_x, and minor design types (cylcone, vertical, and stoker) not likely to be extensively controlled due to dwindling use and/or lack of control flexibility. It should be noted that minor design types are not necessarily insignificant sources of NO_x. For example, cyclone boilers emit approximately 9 percent of stationary source NO_x and rank second among all stationary source design/fuel classifications (Reference 3-2). Yet, the cyclone combustion characteristics make them very difficult to control for NO_x. Their sale has been discontinued for other than high sodium lignite applications, and it is unlikely many existing units will be controlled for NO_x.

Another basis used for source prioritization was fuel availability. To date, gas- and oil-fired utility boilers have been the most extensively controlled, but an increasing number of emissions standards have been set recently for coal units. Few new gas- or oil-fired units are being sold, so NO_x controls for coal units to meet Standards of Performance for New Stationary Sources (NSPS) will dominate in the future. Consequently, this study emphasizes coal-fired units; though NO_x control for gas- and oil-fired units are also treated.

In the following subsections, the characteristics of the major and minor utility boiler types are summarized with respect to: design characteristics, fuels utilization, operational conditions, effluent streams, and emissions. Current dominant designs and new trends are considered. For the purposes of this study, the utility boiler category encompasses all field erected watertube boilers with a heat input greater than 73 MW (250 MBtu/hr) corresponding to an electrical generating capacity of about 25 MW. For purposes of estimating emissions and evaluating the applicability of NO_x controls, since large industrial boilers within the above capacity range are generally similar to the corresponding small utility boilers, large industrial boilers can be effectively grouped with the utility units.

3.1 COAL-FIRED BOILERS

In 1977, utility boilers consumed approximately 12 EJ of coal -- 57 percent of all fossil fuels used by utility boilers (Reference 3-2). According to the National Coal Association (NCA), coal consumption can be expected to increase significantly (Reference 3-3). This projected rapid increase in coal consumption is partly due to pressures on utilities by the government to switch to coal as the primary fuel and a recognition by the utilities themselves of the impending shortages of gas and oil.

The heavy dependence on coal will increase the environmental impact of utility boilers on air quality. Coal is generally more polluting than other conventional fossil fuels. The nitrogen, sulfur, and ash contents of coal give rise to significant NO_x, SO_2, and particulate emissions. These emissions are almost always higher for coal than for gas or oil combustion. In addition, trace elements in the coal account for other pollutants in the flue gases emitted to the atmosphere. Based on the projected widespread use of coal-fired utility boilers in the 1980's and the significant increase in NO_x emissions, these sources will be primary candidates for NO_x controls.

The following sections characterize coal-fired utility boilers. A brief description of each boiler design is presented in Section 3.1.1. Current and projected coal consumption for each coal type and boiler firing type is given in Section 3.1.2. Regional coal consumption is also presented in this section. Section 3.1.3 describes gaseous, liquid, and solid emission streams from coal-fired boilers. Then Section 3.1.4 presents an overview of projected NSPS. NO_x emission inventories by equipment types and geographical locations are also summarized in this section. Finally, Section 3.1.5 describes pollutant control devices commonly installed on these units.

3.1.1 Equipment Types

The major utility boiler designs are the following:

- Tangential
- Single wall
- Opposed wall (often termed horizontally opposed)
- Turbo furnace
- Cyclone
- Vertical
- Stoker

Tangential, single and opposed wall firing, and turbo furnaces are the designs used by the four major utility boiler manufacturers, making up approximately 87 percent of the total boiler population (Reference 3-4). These primary design types are projected for widespread use in the 1980's. Thus, they are candidates for application of NO_x controls and have been extensively evaluated in this study. Since cyclone, vertical, and stoker firing types are either diminishing in use or are unlikely to see widespread use of NO_x controls in the near future, they are considered secondary designs. Table 3-1 describes the major design characteristics, fuel consumption, and trends for each firing type.

The following subsections describe the major design characteristics of each of these boiler types in more detail and preview typical NO_x emissions from these boilers.

TABLE 3-1. SUMMARY OF UTILITY AND LARGE INDUSTRIAL BOILER CHARACTERIZATION (Reference 3-4)

Design Type	Design Characteristics	Typical Process Values	Fuel Consumption (%)	Effluent Streams	Operating Modes	Effects of Transient, Nonstandard Operation	Trends	Future Importance
Tangential	Fuel and air nozzles in each corner of the combustion chamber are directed tangentially to a small firing circle in the chamber. Resulting spin of the flames mixes the fuel and air in the combustion zone.	Input Capacity: 73 MW to 3800 MW Steam Pressure: 18.6 MPa (subcritical) 26.2 MPa (supercritical) Steam Temperature: 755K to 840K Furnace Volume: Up to 38,000 m^3 Furnace Pressure 50 Pa to 1000 Pa Furnace Heat Release: Coal -- 104 to 250 kW/m^3 Oil, gas -- 208 to 518 kW/m^3 Excess Air 25% coal 10% oil 8% gas	67% coal fired 18% oil fired 15% gas fired	Gaseous Flue gas containing flyash, volatilized trace elements, SO_2, NO, other pollutants. Liquid Scrubber streams, ash sluicing streams, wet bottom slag streams. Solid Solid ash removal Flyash removal	Soot blowing, on-off transients, load transients, upsets, fuel additives, rapping, vibrating.	During startup, NO_x emissions are low since flame temperatures not developed. During load reductions, emissions of NO_x decrease because of lower flame temperatures. NO_x should decrease following soot blow due to improved heat transfer.	Trend toward coal firing in new units; conversion to oil and coal in existing units 19.4% of current installed units.	Primary
Single Wall	Burners mounted to single furnace wall -- up to 36 on single wall.	Units typically limited in capacity to about 400 MW (electric) because of furnace area.	43% coal 22% oil fired 35% gas fired	Gaseous Flue gas containing flyash, volatilized trace elements, SO_2, NO, other pollutants. Liquid Scrubber streams, ash sluicing streams, wet bottom slag streams. Solid Solid ash removal Flyash removal	Soot blowing, on-off transients, load transients, upsets, fuel additives, rapping, vibrating.	During startup, NO_x emissions are low since flame temperatures not developed. During load reductions, emissions of NO_x decrease because of lower flame temperatures. NO_x should decrease following soot blow due to improved heat transfer.	Trend toward coal firing in new units; wet bottom units no longer manufactured due to operational problems with low sulfur coals and high combustion temperatures promoting NO_x. 59% of current installed units.	Primary

TABLE 3-1. Continued

Design Type	Design Characteristics	Typical Process Values	Fuel Consumption (%)	Effluent Streams	Operating Modes	Effects of Transient, Nonstandard Operation	Trends	Future Importance
Opposed Wall	Burners are mounted on opposite furnace walls -- up to 48 burners per wall.	Units typically designed in sizes greater than 400 MW (electric).	32% coal 21% oil 47% gas (includes turbo furnace)	Gaseous Flue gas containing flyash, volatilized trace elements, SO_2, NO, other pollutants. Liquid Scrubber streams, ash sluicing streams, wet bottom slag streams. Solid Solid ash removal Flyash removal	Soot blowing, on-off transients load transients, upsets, fuel additives, rapping, vibrating.	During startup, NO_x emissions are low since flame temperatures not developed. During load reductions, emissions of NO_x decrease because of lower flame temperatures. NO_x should decrease following soot blow due to improved heat transfer.	Trend toward coal firing and conversions to oil and coal firing; again, wet bottoms being phased out. 8.2% of current installed units.	Primary
Turbo Furnace	Air and fuel fired down toward furnace bottom using burners spaced across opposed furnace walls. Flame propogates slowly passing vertically to the upper furnace.	Units typically designed in sizes greater than 400 MW (electric)	32% coal 21% oil 47% gas (includes opposed wall)	Gaseous Flue gas containing flyash, volatilized trace elements, SO_2, NO, other pollutants. Liquid Scrubber streams, ash sluicing streams, wet bottom slag streams. Solid Solid ash removal Flyash removal	Soot blowing, on-off transients, load transients, upsets, fuel additives, rapping, vibrating.	During startup, NO_x emissions are low since flame temperatures not developed. During load reductions, emissions of NO_x decrease because of lower flame temperatures. NO_x should decrease following soot blow due to improved heat transfer.	Trend toward coal firing -- (capacity included with opposed wall).	Primary

TABLE 3-1. Concluded

Design Type	Design Characteristics	**Typical Process Values**	Fuel Consumption (%)	Effluent Streams	Operating Modes	Effects of Transient Nonstandard Operation	Trends	Future Importance
Cyclone	Fuel and air introduced circumferentially into cooled furnace to produce swirling, high temperature flame; cyclone chamber separate from main furnace; cyclone furnace must operate at high temperatures since it is a slagging furnace.	Furnace Heat Release: 4.67 to 8.28 MW/m3	92% coal 4% oil 4% gas	Gaseous Flue gas containing flyash, volatilized trace elements, SO_2, NO, and other pollutants. Liquid Scrubber streams Solid Solid ash removal Flyash removal	Soot blowing, on-off transients, load transients, upsets, fuel additives, rapping, vibrating.	During startup, NO_x emissions are low since flame temperatures not developed. During load reductions, emissions of NO_x decrease because of lower flame temperatures. NO_x should decrease following soot blow due to improved heat transfer.	Two cyclone boilers sold since 19/4 have not proven adaptable to emissions regulations. Must operate at high temperatures resulting in high thermal NO_x fixation; also operational problems with low sulfur coal. 3.3% of installed units.	Secondary
Vertical and Stoker	Vertical firing results from downward firing pattern. Used to a limited degree to fire anthracite coal. Stoker projects fuel into the furnace over the fire permitting suspension burning of fine fuel particles. Spreader stokers are the primary design type.	Furnace Heat Release: 1.1 to 1.9 MW/m2	100% coal	Gaseous Flue gas containing flyash, volatilized trace elements, SO_2, NO, and other pollutants. Liquid Scrubber streams Solid Solid ash removal Flyash removal	Soot blowing, on-off transients load transients, upsets, fuel additives, rapping, vibrating.	During startup, NO_x emissions are low since flame temperatures not developed. During load reductions, emissions of NO_x decrease because of lower flame temperatures. NO_x should decrease following soot blow due to improved heat transfer.	Since anthracite usage has declined, vertical fired boilers are no longer sold. Design capacity limitations and high cost have caused stokers usage to diminish. 9.9% of current installed units.	Secondary

3.1.1.1 Tangential Boilers

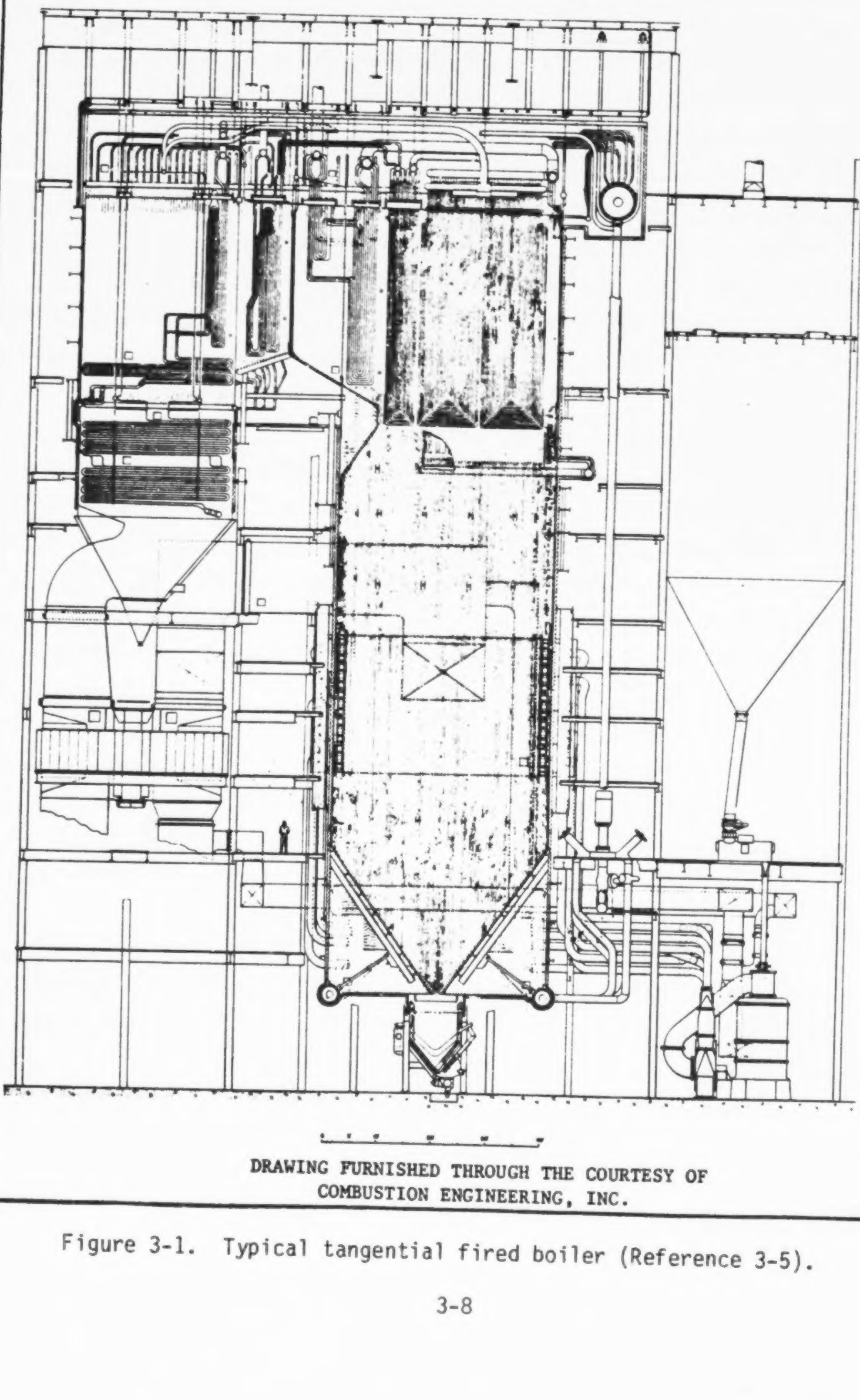
Tangentially fired boilers are characterized by corner firing, with arrays of burners and air nozzles located at the same elevation in each of the four corners of the furnace. Each nozzle is directed tangentially to a small firing circle in the center of the furnace, the actual combustion zone. Figure 3-1 shows a typical tangential coal-fired boiler. In general, tangentially fired boilers emit relatively lower NO_x than other uncontrolled boiler designs. The unique burner arrangement is a primary cause of the lower NO_x emissions.

In tangential boilers, the burners can tilt ±30 degrees from their horizontal setting. Burner tilt is used primarily as a method for superheater steam temperature control. As the convective surfaces of the furnace accumulate flue dust, the heat absorbed from the flue gas continues to decrease. Burners are then tilted upwards to increase the temperature of the flue gas entering the convective section of the boiler. When convective tube fouling becomes severe, soot blowers are used to remove the coating on the tubes. The sudden increase in heat absorption by the clean tubes necessitates tilting the burners down to their original position. As the fouling of the tubes resumes, the tilting burner cycle repeats itself. Burner tilt also affects the level of NO_x emissions (as discussed in Section 6). Optimum burner tilt settings depend on whether the furnace is equipped with overfire air ports.

The twin furnace boiler is another design characteristic of tangential boilers. Tangential boilers larger than 400 MW often include a separate superheat and a reheat furnace. These two furnaces are identical and physically joined side by side in a single unit. However, the flue gas in one furnace does not interact with the gas in the other furnace, except when both gas streams are joined at the stack.

Table 3-1 shows that tangentially fired boilers represent almost 20 percent of the entire boiler population. The majority of these units burn coal as their primary fuel, but it is not uncommon for the furnace to be retrofitted for oil or gas firing.

The average size of tangential coal-fired boilers investigated in this study was 430 MW with a volumetric and surface heat release rate of 112 kW/m^3 and 190 kW/m^2, respectively. The number of burners ranged from 16 to 64.



DRAWING FURNISHED THROUGH THE COURTESY OF COMBUSTION ENGINEERING, INC.

Figure 3-1. Typical tangential fired boiler (Reference 3-5).

3.1.1.2 Significant Design Changes for New Tangential Coal-Fired Boilers

The number of tangential coal-fired boilers in operation that were designed to meet the 1971 NSPS is small compared to the number of pre-NSPS units. Recent reports indicate that 5 to 10 such units were in operation or scheduled to be online by the end of 1977 (References 3-6 and 3-7). If the average unit size at an electrical output of 600 MW is assumed, this amounts to less than 2 percent of installed conventional steam driven generating capacity (References 3-8 and 3-9). The small number of units in operation that were designed to meet 1971 NSPS is an indication of the length of time required to design, fabricate, and install electric utility powerplant components.

The tangential firing design is inherently a low NO_x producer. Of 28 pre-NSPS tangential coal-fired boilers, 23 units met NSPS under normal operating conditions (Reference 3-7). Still, there are several significant changes in the design of more recent tangential coal-fired units for specifically meeting NSPS. These changes include the addition of overfire air ports, and increased furnace height and plan area (References 3-7 and 3-10).

Overfire air (OFA) ports are included in the design of all new tangential coal-fired boilers. The overfire air ports permit off stoichiometric combustion by reducing the airflow to the burner zone and adding air above the burner zone. For a normal overall operating level of 125 percent theoretical air, the burner zone theoretical air is reduced to 105 to 110 percent with the remainder of the combustion air introduced through the OFA ports. Furnace slagging and tube wastage problems associated with substoichiometric firing are reduced by firing with a small amount of excess air in the burner zone and by the tangential firing design, which facilitates burning the fuel near the center of the furnace, away from the furnace walls (References 3-7 and 3-10). Airflow to each fuel nozzle, secondary air port, and overfire air port can be regulated by individual dampers.

The furnace volumes of present designs are 15 to 20 percent larger than in designs of the 1960's. This change was made to reduce slagging problems associated with higher heat release rates (Reference 3-6). The reduced heat release rate reduces thermal conversion of nitrogen to NO_x.

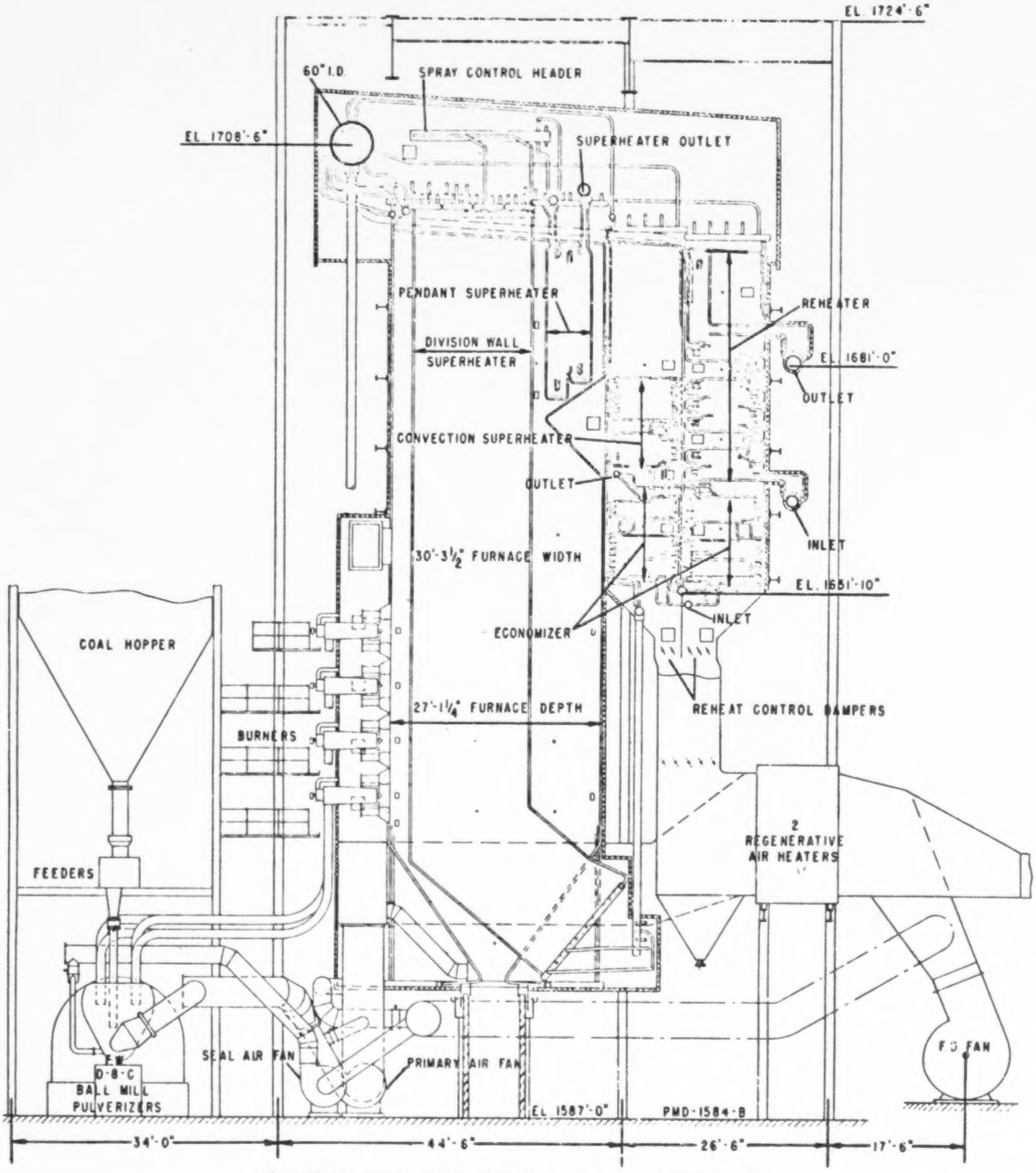
3.1.1.3 Single and Opposed Wall Fired Boilers

Single and opposed wall fired boilers are essentially similar in design. They only differ in the number of furnace walls equipped with burners and in furnace depth. Single wall fired boilers have all burners on the front or rear walls. The term front or rear wall fired boilers is often used to make this distinction. Opposed wall fired boilers instead have burners arranged on both the front and rear walls, horizontally facing each other. Figures 3-2 and 3-3 show front wall and opposed wall fired boilers, respectively.

A variation of the opposed wall design is the turbo furnace manufactured exclusively by Riley Stoker. This design is unique because of its venturi shaped cross section and directional flame burners. In the Riley turbo coal-fired furnace, air and coal are injected downward toward the furnace bottom below the venturi throat. According to Riley, this furnace design will produce lower thermal NO_x emissions than uncontrolled conventional wall fired boilers (Reference 3-11). A schematic of a typical coal-fired turbo furnace is shown in Figure 3-4.

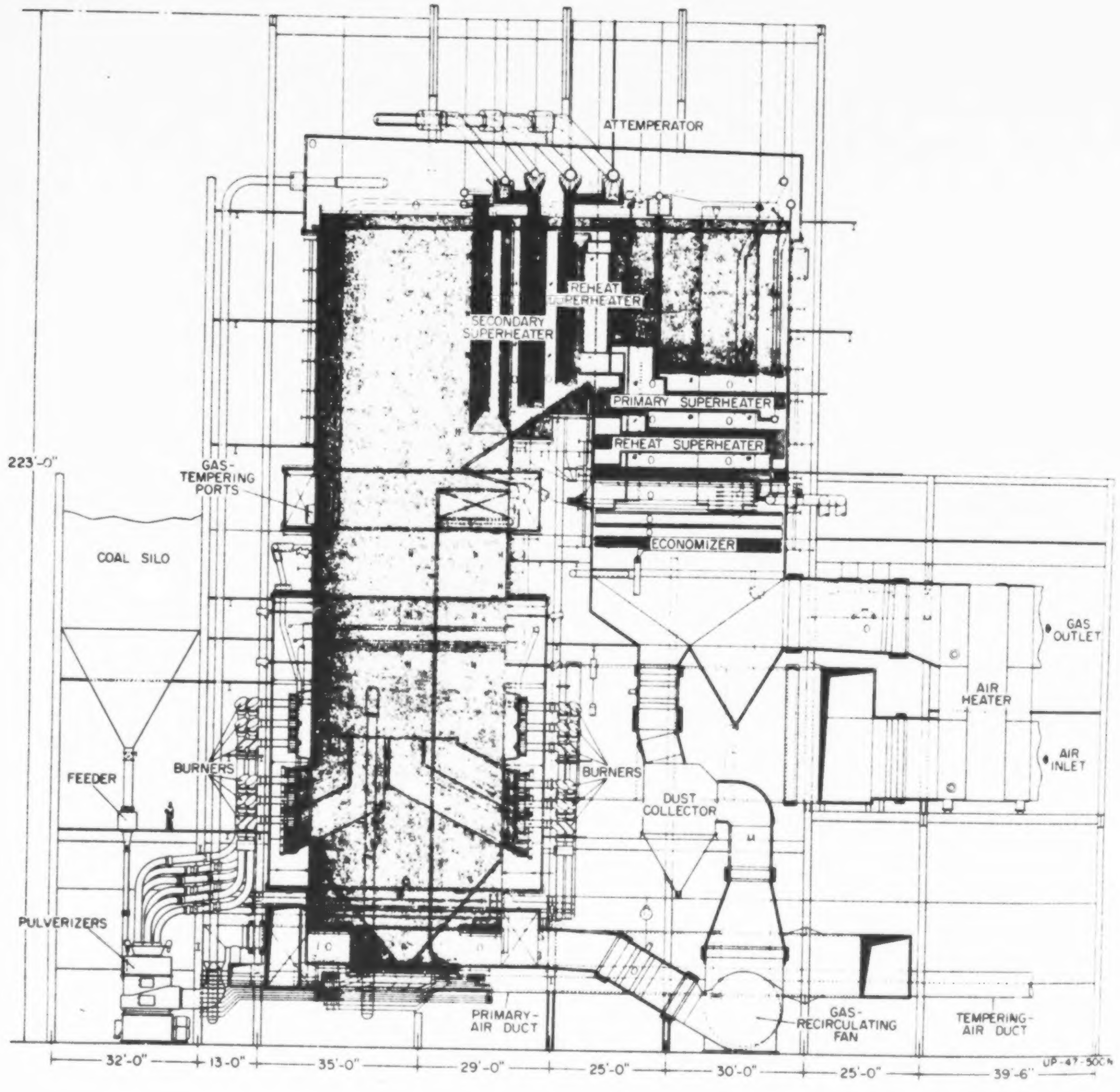
Contrary to tangential boiler designs, the burners on these firing types (except for turbo furnace designs) do not tilt. Superheater steam temperatures are controlled by excess air level, heat input, flue gas recirculation, and/or steam attemperation. Generally, the twin furnace design is not found in either the single or opposed wall firing design. Instead, division walls are occasionally installed in these boilers to increase the heat transfer surface of the unit without enlarging the overall size of the firebox. These walls divide the firebox from the furnace bottom up to a distance of about 3 meters (10 feet) above the top burner level. The flue gases from the two furnace boilers join before they enter the convective section of the boiler. Division walls are not as popular on current design coal-fired boilers as on gas- and oil-fired boilers because coal ash deposits are difficult to clean from the wall surface.

Single and opposed wall fired boilers accounted for 67 percent of the total installed utility boiler population in 1974 (see Table 3-1). However, their combined coal consumption amounted to only 35 percent of the total coal consumed by utility boilers in 1977 (Reference 3-2).


EL. 1724'-6"
60" I.D.
SPRAY CONTROL HEADER
EL. 1708'-6"
SUPERHEATER OUTLET
PENDANT SUPERHEATER
REHEATER
DIVISION WALL SUPERHEATER
EL. 1681'-0"
OUTLET
CONVECTION SUPERHEATER
OUTLET
INLET
30'-3½" FURNACE WIDTH
EL. 1651'-10"
INLET
ECONOMIZER
COAL HOPPER
REHEAT CONTROL DAMPERS
27'-1¼" FURNACE DEPTH
BURNERS
2 REGENERATIVE AIR HEATERS
FEEDERS
SEAL AIR FAN
PRIMARY AIR FAN
F.D. FAN
F.W. D-8-C BALL MILL PULVERIZERS
EL. 1587'-0"
PMD-1584-B
34'-0"
44'-6"
26'-6"
17'-6"

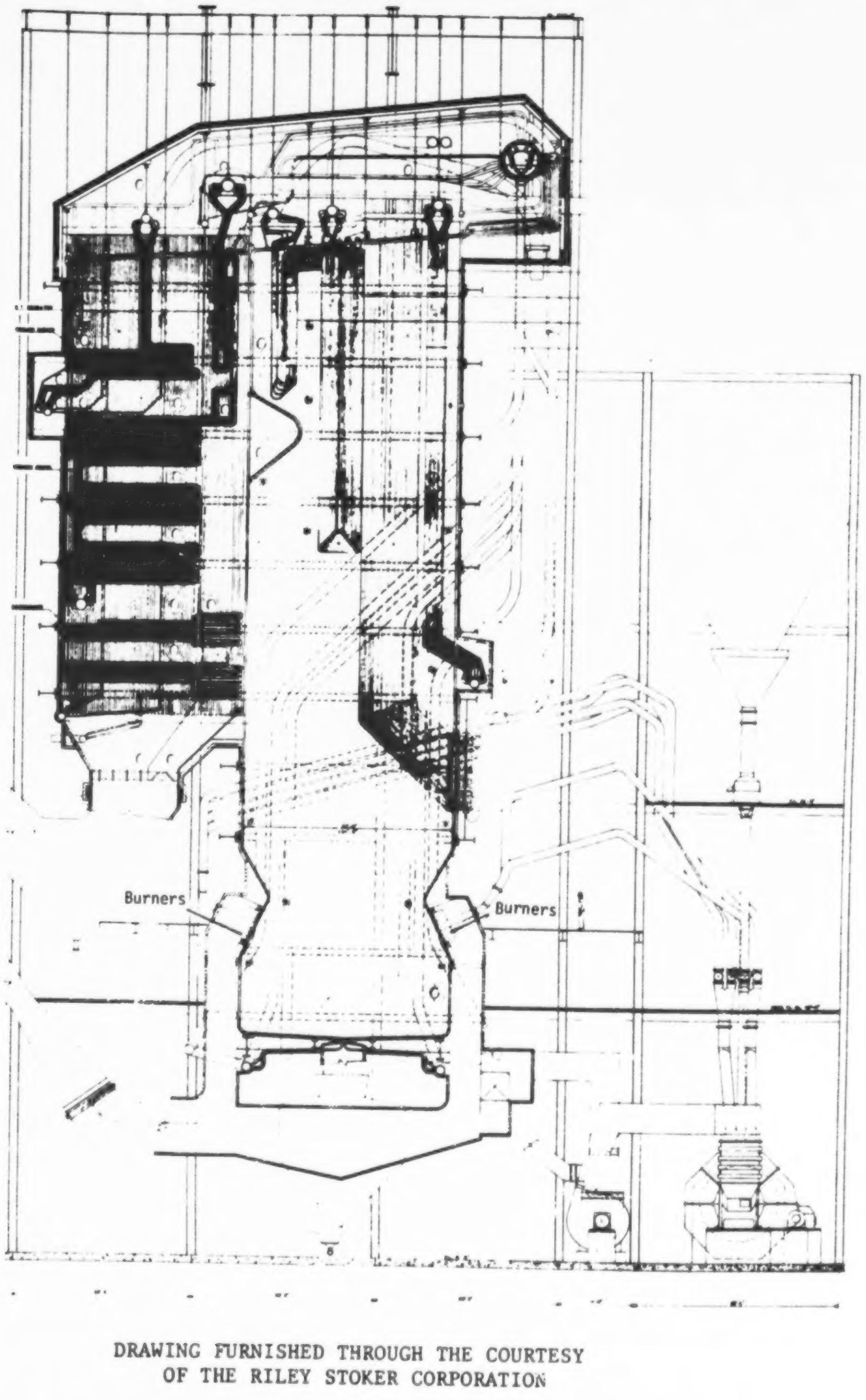
DRAWING FURNISHED THROUGH THE COURTESY OF THE FOSTER WHEELER CORPORATION

Figure 3-2. Typical front wall fired boiler (Reference 3-5).


ATTEMPERATOR
REHEAT SUPERHEATER
SECONDARY SUPERHEATER
PRIMARY SUPERHEATER
REHEAT SUPERHEATER
223'-0"
GAS-TEMPERING PORTS
COAL SILO
ECONOMIZER
GAS OUTLET
AIR HEATER
AIR INLET
FEEDER
BURNERS
BURNERS
DUST COLLECTOR
PULVERIZERS
PRIMARY-AIR DUCT
GAS-RECIRCULATING FAN
TEMPERING-AIR DUCT
32'-0"
13-0"
35'-0"
29'-0"
25'-0"
30'-0"
25'-0"
39'-6"
UP-47-50C4

DRAWING FURNISHED THROUGH THE COURTESY OF
THE BABCOCK AND WILCOX COMPANY

Figure 3-3. Typical opposed wall fired boiler (Reference 3-5).



Burners
Burners

DRAWING FURNISHED THROUGH THE COURTESY
OF THE RILEY STOKER CORPORATION

Figure 3-4. Typical turbo furnace fired boiler (Reference 3-5).

This consumption compares to 48 percent for tangential boilers. The main reason for this difference is that single wall fired boilers are relatively smaller in size. Single wall fired boilers are seldom greater than 400 MW electrical output. Opposed wall boilers are often larger. Of all boilers investigated in this study, the average size (electrical output) of the single wall coal-fired boilers was 200 MW; the average opposed wall boiler was 580 MW.

Inventory data on turbo fired furnaces are often reported in conjunction with opposed wall boilers. The total number of turbo fired furnaces currently supplying steam for the utilities is not widely known. Therefore, for the purposes of fuel consumption and emissions inventory discussions, turbo fired and opposed wall boilers are treated in this section as a single equipment type.

3.1.1.4 Significant Design Changes for New Single and Opposed Wall Coal-Fired Boilers

The number of coal fired single and opposed wall boilers (hereafter collectively referred to as wall fired boilers) in operation that were designed to meet 1971 NSPS is small compared to the number of pre-NSPS units. A recent survey showed that nine such units were in operation or scheduled to be online by the end of 1977 (Reference 3-6). This represents an installed capacity of 5127 MW, less than 2 percent of installed conventional steam driven generating capacity (Reference 3-8).

There are several significant changes in the design of coal-burning, wall fired electric utility boilers for meeting NSPS. The primary changes include new burner designs, addition of overfire air ports, improvement in the control of air distribution to the burners, increased burner spacing, and enlargment of the furnace plan area.

The new burner designs are of a limited turbulence design, as discussed in Section 5. These burners control the mixing rates of coal and air. This tends to delay combustion and thereby reduce the peak combustion temperatures, limiting the thermal conversion of nitrogen to NO_x. Controlling the oxygen availability, by controlling the rate of mixing of coal and air, in addition reduces the conversion of fuel nitrogen to NO_x. Reduction in NO_x emissions of 45 to 60 percent due to burner design have been indicated (References 3-12 and 3-13).

Overfire air ports are included in many coal-burning, wall fired units. The overfire air ports permit off stoichiometric combustion by reducing the airflow to the burners and adding air above the burner zone. Of course, effectively staging combustion in this manner raises the potential for substoichiometric conditions to exist in the lower furnace. While effective for NO_x control, substoichiometric combustion of coal increases the potential for slagging of the furnace, corrosion, and increased tube wastage. These problems have been attacked either by reducing the degree of staging, or by introducing air at the furnace wall to provide a local oxidizing atmosphere while retaining substoichiometric conditions in the furnace.

The use of low NO_x burners and overfire air requires accurate control of airflow to the burners and overfire air ports. The methods that have been used to effect this are the compartmented windbox and the perforated plate air hood. With the compartmented windbox, all burners served by one pulverizer are served by one windbox compartment. Airflow to the compartment is regulated. With the perforated plate air hood, airflow can be regulated on an individual burner basis.

The burner spacing and the furnace plan area have also been increased for wall fired NSPS units. These changes reduce the burner zone heat release rates. The reduced heat release rate results in a lower level of thermal conversion of air nitrogen to NO_x. Pre-NSPS designs generated approximately 50 percent thermal NO_x and 50 percent fuel NO_x. With the reduced heat release rates, thermal NO_x generally accounts for only 25 percent of total NO_x generation (Reference 3-13). Although the increase in furnace plan area reduces thermal NO_x, it was incorporated into unit design by at least one manufacturer prior to NSPS implementation. A change in heat input/furnace plan area from 6.6 kW/m^2 (2.1×10^6 Btu/ft^2-hr) to 5.7 kW/m^2 (1.8×10^6 Btu/ft^2-hr) was made to reduce the potential for slag accumulation on the furnace walls (Reference 3-14).

The combined effects of the changes discussed above allow manufacturers to guarantee that their coal, wall fired units will meet 1971 NSPS levels for NO_x emissions.

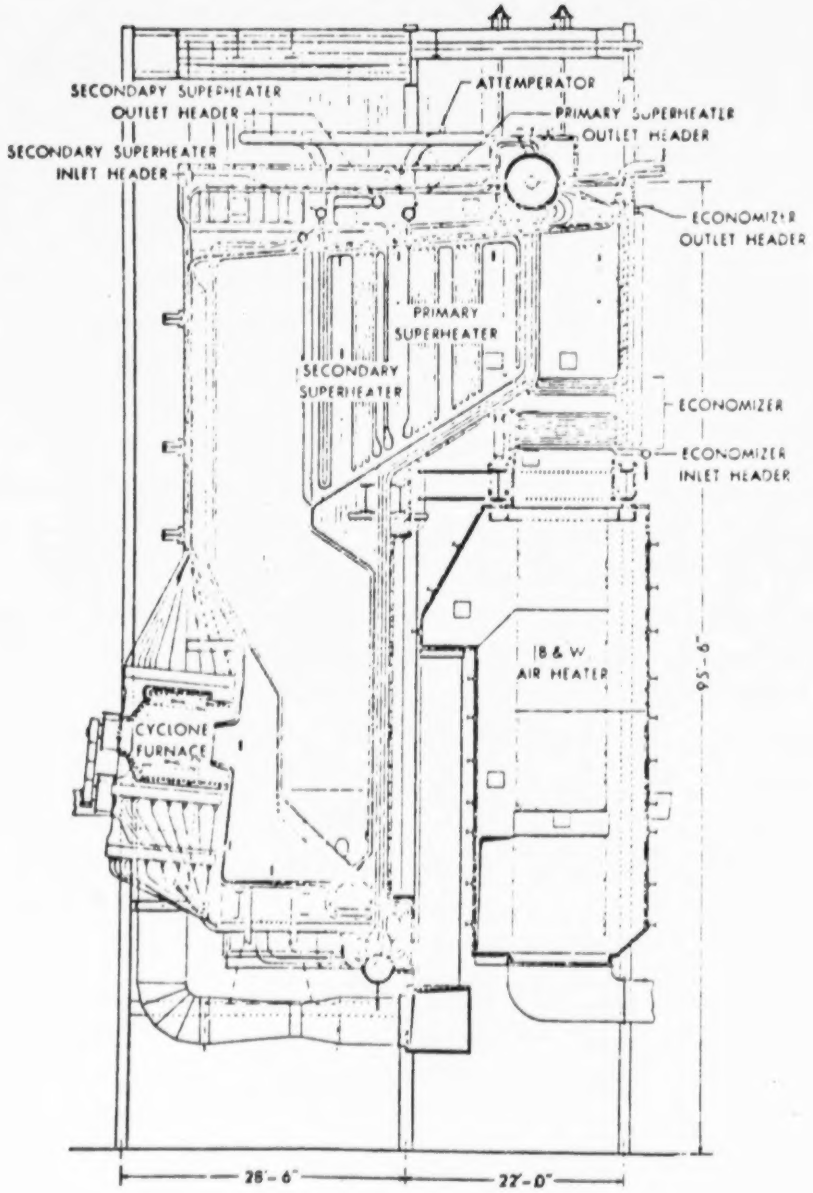
3.1.1.5 "Minor" Design Boilers

Stokers, vertical, and cyclone units are categorized as "minor" design types because relatively few boilers of this type are currently being used by the utilities. The combined number of vertical and stoker boilers in 1974 accounted for 9.9 percent of the entire utility and large industrial boiler population. Cyclone boilers accounted for only 3.3 percent (see Table 3-1). The combined utility population of stokers, vertical and cyclone boilers is expected to even further decrease for the reasons discussed below.

Stoker fired furnaces for utilities are seldom found in the field, as past trends have been toward larger capacity boilers. Stoker sizes are usually limited to 40 MW electric output. Stoker fired units also operate at lower efficiency than pulverized coal units. Design capacity limitations and high operating costs have made the stoker an uncommon utility equipment type (Reference 3-15).

Vertical furnaces were developed for pulverized fuels before the advent of water walled combustion chambers. They were also previously used to a limited degree to fire anthracite coal. Anthracite is difficult to burn in conventional boilers because of its low volatile content. The long residence time resulting from the downward firing pattern in vertical furnaces was effective in achieving ignition and char burnout for anthracite. However, with the decline of anthracite as a utility fuel, vertical furnaces are no longer sold and few are found in the field.

Cyclone furnaces were being sold as late as 1974, but because the units have not proven adaptable for emissions control reasons, sales have halted for all but high sodium lignite applications. These furnaces were originally developed by B&W to burn low ash fusion temperature Illinois coal, but they have recently been used successfully with lignite. In this design, fuel and air are introduced circumferentially into the water-cooled cyclone furnace to produce a high swirl, high temperature flame. The cyclone furnace must operate at high combustion temperatures (Reference 3-16), since it is designed to operate as a slagging furnace. However, since high temperatures result in high thermal NO_x formation, the cyclone furnace has lost much of its market. Figure 3-5 shows a schematic of a typical cyclone fired boiler.


SECONDARY SUPERHEATER OUTLET HEADER
SECONDARY SUPERHEATER INLET HEADER
ATTEMPERATOR
PRIMARY SUPERHEATER OUTLET HEADER
ECONOMIZER OUTLET HEADER
PRIMARY SUPERHEATER
SECONDARY SUPERHEATER
ECONOMIZER
ECONOMIZER INLET HEADER
B & W AIR HEATER
CYCLONE FURNACE
95'-6"
28'-6"
22'-0"

DRAWING FURNISHED THROUGH THE COURTESY OF
THE BABCOCK & WILCOX COMPANY

Figure 3-5. Typical cyclone fired boiler (Reference 3-5).

3.1.2 Coal Consumption

The data available on coal consumption in utility boilers is summarized in this section. Since NO_x emissions from a utility boiler can vary significantly as a function of both coal type burned and equipment design, data on both are discussed. Coal consumption by equipment type is described in Section 3.1.2.1, while coal consumption by coal type is described in Section 3.1.2.2. Regional coal consumption by the utility industry is reviewed in Section 3.1.2.3.

3.1.2.1 Coal Consumption by Equipment Type

Table 3-2 lists the amount of coal burned for each utility equipment type discussed in the previous section. In 1977 energy from coal reached 12 EJ (11 x 10^{15} Btu), corresponding to 57 percent of the total fuel consumed by all utility boilers. Coal consumption data in the utility sector were obtained from References 3-16 through 3-27.

In spite of the environmental problems inherent in the recovery and utilization of large quantities of coal, the trend toward increased coal use is expected to continue. Table 3-2 also gives the projected coal consumption for utility equipment types in the years 1985 and 2000. For the year 2000, two energy scenarios -- high nuclear and low nuclear energy contributions -- are used.

These energy scenarios were developed primarily from the DOE Midterm Analysis Report and two EPRI documents (References 3-28 through 3-30). The DOE report was used because of its recent analysis of the National Energy Act. The two EPRI reports provide alternative energy growth scenarios. All three studies were used because of the technical expertise, the high visibility, and wide circulation of these results.

The growth in electric demand is high, with electric generation capacity growing at between 5 and 6 percent per year. Coal and nuclear will meet most of the electric demand, with synfuels, oil, and gas contributing a small fraction.

In the low nuclear case, there is a heavy emphasis on utility coal use, and no new nuclear capacity projected after 1985. In 2000, coal will contribute 60 percent to total electricity generation and nuclear only 16 percent. For all sectors, this case is projected to use 41 percent more fossil fuels than in the case of maximum conservation. This scenario would occur if there were increased pressure to use our coal resources to meet future energy demand and if construction of nuclear powerplants continues to be slow.

TABLE 3-2. UTILITY COAL CONSUMPTION, (EJ)

Equipment Type	1977	1985	2000	
			Low Nuclear	High Nuclear
Tangential	5.8 (28)[a]	10 (39)	36 (52)	23 (48)
Single Wall	3.0 (14)	2.7 (11)	2.8 (4.0)	2.4 (5.0)
Opposed Wall and Turbo Furnace	1.2 (5.7)	4.6 (18)	23 (33)	15 (32)
Cyclone	1.5 (7.2)	1.3 (5.1)	0.83 (1.1)	0.83 (1.7)
Vertical and Stoker	0.32 (1.5)	0.27 (1.1)	0.18 (0.26)	0.18 (0.38)
All Boilers	12 (57)	19 (74)	63 (91)	41 (86)

[a] Percent of total utility fuel consumption is given in parentheses.

In the high nuclear scenario, nuclear powerplants are projected to supply 40 percent of the utility sector's electric generation by the year 2000.

Table 3-2 shows that corner fired boilers will continue to be the preferred coal combustion equipment. By the year 2000, tangential boilers are predicted to produce over 50 percent of all electrical energy from utilities by burning coal. Opposed wall fired boilers will be the second most common coal firing equipment in the year 2000, with the remaining boiler types decreasing coal consumption from 1977 levels.

3.1.2.2 Coal Consumption by Coal Types

Coal is an extremely heterogeneous fuel whose chemical and physical properties vary significantly between places of origin. Of these properties, the two most routinely monitored by utilities are sulfur and ash content. Sulfur (S) and ash (A) contents of the following coals are considered representative of utility boiler consumption:

- Bituminous and sub-bituminous
    - -- Interior province (high sulfur) -- 2.8 percent S, 9.0 percent A
    - -- Eastern province (medium sulfur) -- 2.2 percent S, 9.2 percent A
    - -- Western province (low sulfur) -- 1.6 percent S, 8.7 percent A
    - -- North Dakota lignite, 0.4 percent S, 12.8 percent A
    - -- Pennsylvania anthracite, 0.6 percent S, 11.9 percent A

The medium sulfur levels correspond to the average sulfur concentration of coals used in U.S. utilities in 1974 (Reference 3-17).

Trace element content of individual coal samples is also highly variable, typically varying within a single coal-producing region, and even within a single seam (Reference 3-31). However, representative concentration levels for coal have been determined and are listed in Table 3-3 together with corresponding sulfur, ash, and heating value contents.

Table 3-4 presents the trend in utility consumption of these coal types. This table was drafted with information from Reference 3-2. The data show that for both energy scenarios, low and high nuclear, described above, the increase in consumption of medium and low sulfur bituminous and sub-bituminous Western coals combined will be more significant than the high sulfur Eastern coals. This conclusion was based on stringent sulfur oxide regulations and economic tradeoffs -- switching to low sulfur coals versus implementation of scrubbing devices. Anthracite coal consumption is expected to be substantially reduced.

3.1.2.3 Regional Coal Consumption

The distribution of fuel consumption for utility boilers by region is given in Table 3-5. In compiling this table, regions were used to partition national coal consumption geographically. This table was obtained from

TABLE 3-3. PROPERTIES AND TRACE ELEMENTS OF REPRESENTATIVE U.S. COALS (Reference 3-4)

	Anthracite Coal	Sub-bituminous & Bituminous			Lignite Coal
		High S	Medium S	Low S	
Ash (percent)	11.9	9	9.2	8.7	12.8
Sulfur (percent)	0.6	2.8	2.2	1.6	0.4
Heating Value (kJ/kg)	30,238	27,912	27,912	23,260	18,608
Al (ppm)	--	12,240		10,200	8,160
Sb	0.1	1.3		1.1	0.9
As	9.3	15		13	10
Ba	54	36		30	24
Be	2.8	1.7		1.5	1.2
Bi	0.1	1.0		0.8	0.7
B	1.0	114		95	76
Cd	0.1	2.9		2.4	2.0
Co	84	9.1		7.6	6.1
Cr	112	14		12	10
Cu	70	40		33	26
Pb	8.3	14		12	9.2
Mn	169	53		45	36
Hg	0.3	0.2		0.2	0.1
Mo	9.3	8.0		6.7	5.3
Ni	47	22		19	15
P	--	63		53	42
Se	0.2	2.0		1.7	1.3
V	12	33		28	22
Zn	31	312		260	208
Zr	45	72		60	48

TABLE 3-4. UTILITY COAL CONSUMPTION BY COAL TYPES, (EJ)

Coal Type	1977	1985	2000	
			Low Nuclear	High Nuclear
Medium Sulfur Bituminous and Sub-bituminous	5.3 (25)[a]	8.9 (35)	31 (44)	20 (42)
High Sulfur Bituminous and Sub-bituminous	4.6 (22)	6.9 (27)	21 (31)	14 (29)
Low Sulfur Bituminous and Sub-bituminous	1.7 (8.1)	2.9 (11)	10 (15)	6.5 (14)
Lignite	0.25 (1.2)	0.32 (1.3)	0.82 (1.2)	0.55 (1.2)
Anthracite	0.10 (0.48)	0.088 (0.34)	0.057 (0.082)	0.057 (0.12)

[a] Percent of total utility fuel consumption is given in parentheses.

TABLE 3-5. REGIONAL COAL CONSUMPTION BY EQUIPMENT TYPE IN 1974, (Percent) (Reference 3-32)

Equipment Type	New England	Middle Atlantic	E-N-Central	W-N-Central	South Atlantic	E-S-Central	W-S-Central	Mountain	Pacific	Total
Tangential	0.25	5.4	16	4.5	10	6.5	0.63	3.3	0.38	47
Single Wall	0.14	3.1	9.2	2.6	5.4	4.2	0.56	1.9	0.22	27
Opposed Wall	0.04	0.89	2.6	0.73	1.6	1.2	0.10	0.54	0.06	7.8
Cyclone	0.08	1.7	5.0	1.4	2.9	2.3	0.19	1.0	0.12	15
Vertical and Stoker	0.02	0.36	1.1	0.29	0.62	0.49	0.04	0.22	0.03	3.2
Total	0.53	11	34	9.4	21	15	1.3	6.9	0.81	100

information in Reference 3-32. These regions are also used in data compiled by the Federal Power Commission (FPC) and the Bureau of Mines. The following sources were used to compile the regional coal consumption estimates.

- Federal Power Commission -- fuel consumption by type of fuel and sulfur content (Reference 3-33)
- Bureau of Mines -- data on domestic fossil fuel production and end use by state (Reference 3-34)
- National Emissions Data System (NEDS) -- fuel consumption by region and end use (Reference 3-35)
- Battelle -- analysis of boiler populations and fuels (Reference 3-25)

As shown by this geographical fuel distribution, relatively little coal is used the New England, Pacific, and West South-Central regions, where oil and natural gas consumption prevails.

3.1.3 Utility Boiler Combustion Process and Effluent Streams

Utility boilers have several multimedia effluent streams which may be affected by altering the combustion process to control NO_x formation. This section briefly discusses the combustion process in utility boilers and identifies the multimedia effluent streams emitting from these units. It also includes a listing of nonconventional operating practices which may affect the makeup of these effluent streams. The following discussion concentrates on coal since it is the main fuel now used in utility boilers, and it requires more process equipment than other fuels.

Types of processes in utility boilers include fuel combustion, flue gas cleaning, ash removal, and fireside boiler tube cleanup. Figure 3-6 gives a flow diagram for a typical pulverized coal-fueled boiler, showing how these four processes relate to each other.

The fuel combustion process in utility boilers produces bottom or hopper ash, combustion gases, volatilized noncombustible contaminants of the fuel, and suspended ash entrained in the hot flue gases. Coal usually contains between 5 and 15 percent ash and up to about 60 trace elements.* Residual fuel oils contain less than 0.2 percent ash, but may have

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*Trace defined as <1 percent by weight of coal

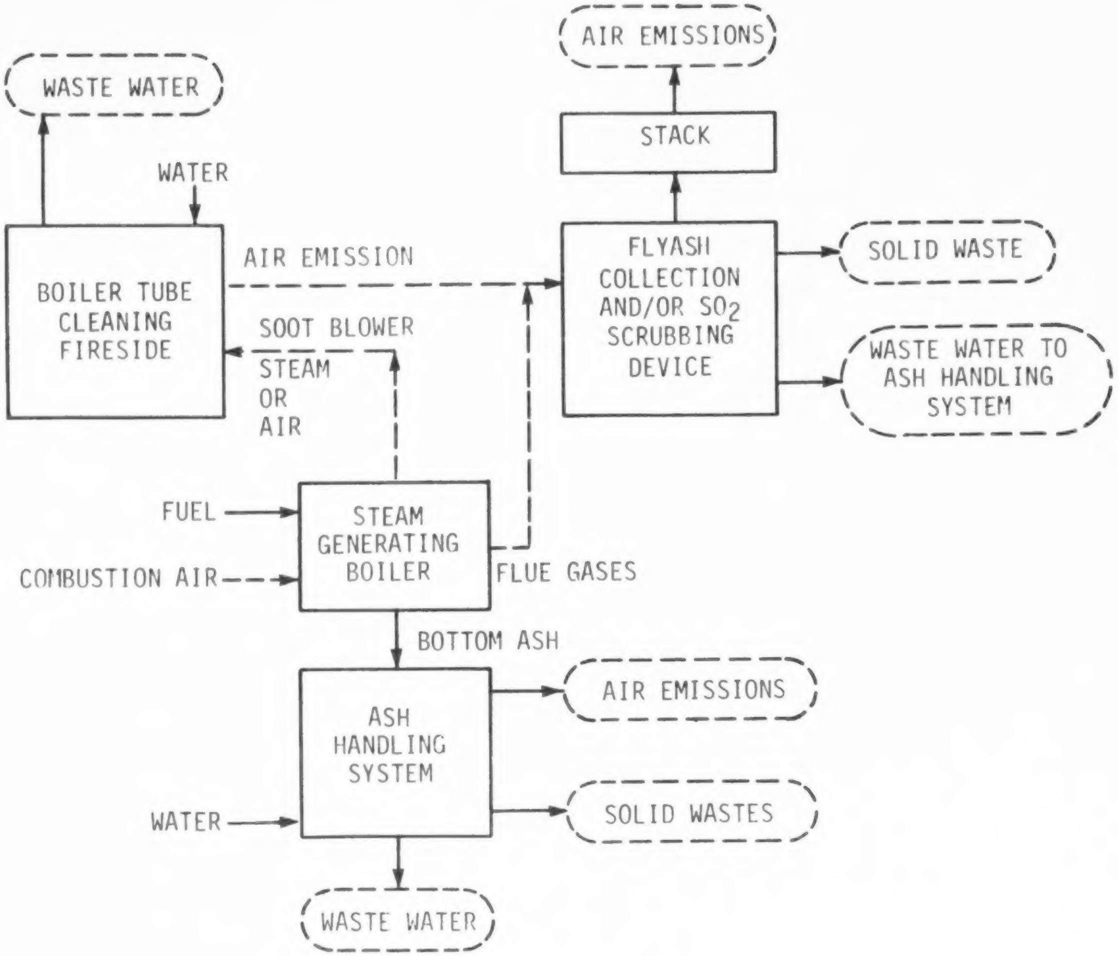

WASTE WATER
WATER
BOILER TUBE CLEANING FIRESIDE
AIR EMISSION
SOOT BLOWER
STEAM OR AIR
AIR EMISSIONS
STACK
FLYASH COLLECTION AND/OR SO_2 SCRUBBING DEVICE
SOLID WASTE
WASTE WATER TO ASH HANDLING SYSTEM
FUEL
COMBUSTION AIR
STEAM GENERATING BOILER
FLUE GASES
BOTTOM ASH
ASH HANDLING SYSTEM
AIR EMISSIONS
SOLID WASTES
WATER
WASTE WATER

Figure 3-6. Coal-fired utility boiler combustion process flow diagram (Reference 3-1).

significant amounts of trace metallics, particularly vanadium. Natural gas contains virtually no ash or trace element constituents.

Up to 65 percent of the ash in coal is entrained in the hot combustion gases and either deposited on various boiler parts or carried out of the boiler to the flyash collection system. Flue gas cleanup generally consists of particulate removal equipment (cyclone, electrostatic precipitator, or baghouse). Sulfur dioxide removal devices are employed on less than 5 percent of current installations. The flyash collection equipment usually produces a dry solid waste stream which is removed either in the dry state or by a water sluicing stream which is diverted to an ash settling pond. A recent analysis of powerplant data (Reference 3-22) shows that about 80 percent of utility boilers remove ash by sluice water, and the remaining 20 percent use dry removal.

The entrained ash deposited on furnace walls or other heat transfer sections may reduce heat transfer efficiency and lead to severe slagging or fouling if not removed. Soot blowing systems using steam or compressed air are used to maintain fireside tube surfaces on a regular schedule depending upon fuel and load. The soot blown off the boiler tubes becomes entrained in the flue gases or settles in the superheater or economizer ash hoppers.

Coal ash which is not entrained in combustion gases either falls dry to the furnace hopper (dry bottom) or melts and adheres to the furnace wall and flows into a slag tank (wet bottom). Dry ash is removed by way of a pnuematic conveyance system or by a water sluicing stream to an ash settling pond. Superheater and economizer ash hoppers generally produce insignificant amounts of ash compared to the furnace hopper and the flyash collection system. Table 3-6 summarizes the effluent streams associated with the combustion process in utility boilers.

Several periodic or nonstandard operating procedures can affect the composition of the various effluent streams discussed above. Although sootblowing was described above because it is so commonly used, it is also included in the following periodic or nonstandard operations:

- Sootblowing
- Startup or shutdown transients
- Load changes

TABLE 3-6. COMBUSTION RELATED EFFLUENT STREAMS FROM A UTILITY BOILER (Reference 3-1)

Stream/Fuel	Pulverized Coal	Fuel Oil	Natural Gas
Gaseous effluent streams	Flue gas containing flyash, volatilized trace elements, SO_2, NO, other pollutants	Flue gas containing volatilized trace elements, flyash, NO, SO_2, other pollutants	Flue gas containing NO, other pollutants
Liquid effluent stream	Scrubber streams Ash sluicing stream Wet bottom slag stream	Scrubber stream Ash sluicing stream (if any)	None
Solid	Solid ash removal	Solid ash removal (if any)	None

- Fuel additives
- Rapping or vibrating
- Flameout
- Upsets
- Equipment failure

Table 3-7 shows how often these operations take place and the effluent streams which they may affect.

3.1.4 NO_x Emissions Inventory

This section describes the contribution of coal-fired utility boilers to total stationary source NO_x emissions, beginning with an estimate of future NO_x control levels in Section 3.1.4.1. The fuel consumption data of Section 3.1.2 were then used to calculate total NO_x emissions. These emissions are partitioned by equipment firing type in Section 3.1.4.2 and by region in Section 3.1.4.3.

TABLE 3-7. EFFECT OF NONSTANDARD OPERATING PROCEDURES ON THE EFFLUENT STREAMS FROM A DRY BOTTOM PULVERIZED COAL-FIRED BOILER (Reference 3-5)

Procedure	Frequency	Gaseous	Liquid	Solid
Soot Blowing	3 to 4/day	●[a]	●	●
Startup, Shutdown	12 to 50/yr	●	●	
Load Change	1/day	●	●	
Fuel Additives	Continuous if used	●	●	●
Rapping, Vibrating	3 to 4/day	●	●	●
Flameout	1/yr	●		●
Upset	1/yr	●		
Equipment Failure	Several/yr	●	●	●

[a] Indicates possible affect on stream composition

3.1.4.1 Estimated Future NO_x Control Levels

In projecting emissions, the effects of controls implementation must be incorporated. For this reason, future emission control levels were projected, based on estimated availability schedules of emerging near- and far-term utility boiler NO_x control techniques (outlined in Section 4). These projected control levels are listed in Table 3-8.

The recently promulgated standards (1979) for coal-fired boilers break out specific coal types, specifically:

- Units firing subbituminous coal are limited to NO_x emissions of 215 ng/J (0.5 lb/10^6 Btu)
- Units firing bituminous and anthractie coals are limited to 258 ng/J (0.6 lb/10^6 Btu)
- Units firing coal containing greater than 25 percent North Dakota, South Dakota, or Montana lignite in a cyclone furnace are limited to 344 ng/J (0.8 lb/10^6 Btu)

The effects of dividing standards by coal type, though not included in this report, will be factored into future studies.

TABLE 3-8. PROJECTED FUTURE NO_x CONTROL LEVELS FOR UTILITY BOILERS

Fuel	Estimated Implementation Date	Control Level ng/J (lb/10^6 Btu)
Coal	1971 (Promulgated standard)	301 (0.7)
	1979 (Promulgated standard)	258 (0.6) to 215 (0.5)
	1983	129 (0.3)
	1988	86 (0.2)
Oil	1971 (Promulgated standard)	129 (0.3)
Gas	1971 (Promulagted standard)	86 (0.2)

3.1.4.2 NO_x Emissions by Equipment Type

Table 3-9 lists the emissions from coal-fired units for all the boiler design types. All entries in this table were obtained from Reference 3-2. Projected NO_x emissions for the year 1985 and 2000 were compiled by using the projected coal consumption and the estimated NSPS controls.

Even with the implementation of the projected NSPS, NO_x emissions from coal-fired utility boilers in the year 2000 will increase by two-thirds for the high nuclear scenario and more than double for the low nuclear scenario. The contribution of tangential coal-fired boilers to the total stationary NO_x emissions also increases significantly and will account for one-third to one-half of the total NO_x emitted from stationary sources, depending on the contribution of nuclear power.

TABLE 3-9. NO_x EMISSIONS FROM COAL-FIRED UTILITY BOILERS, (Gg/yr)

Equipment Type	1977	1985	2000	
			Low Nuclear	High Nuclear
Tangential	1500 (25)[a]	2500 (34)	5400 (49)	3800 (44)
Single Wall	1500 (25)	1300 (18)	1000 (9.1)	1100 (13)
Opposed Wall	600 (10)	1600 (22)	3200 (29)	2200 (25)
Vertical and Stoker	100 (1.7)	87 (1.2)	56 (0.51)	56 (0.65)
Cyclone	950 (16)	800 (11)	520 (4.7)	520 (6.0)
Total	4600 (78)	6300 (87)	10,000 (92)	7700 (89)

[a] Percent of total stationary sources

The trend is not the same for the minor firing design types. NO_x emissions from these boilers decrease steadily for all scenarios. Since few new cyclone and no new vertical or stoker boilers are expected to be purchased by the utilities in the future, the existing units will be slowly phased out. Their combined contribution to NO_x emissions from stationary sources is expected to be 5 to 7 percent by the year 2000. Emissions from turbo furnace boilers are included with emissions from horizontally oppposed boilers.

3.1.4.3 Regional NO_x Emissions Inventory

This section presents regional NO_x emissions for coal-fired utility boilers. Table 3-10 summarizes the percent of emissions for each of the nine regions addressed. These inventories result from the regional coal consumption data for 1974 presented in Reference 3-32. Over 50 percent of all NO_x emissions from coal-fired utility boilers are from the East-North Central and South Atlantic regions. New England contributes less than 1 percent of the total NO_x emissions from coal-fired units. The West-North Central, West-South Central, and Pacific regions combined contribute only 12 percent of the total NO_x emissions from coal-fired utility boilers. These Western regions will be strongly affected by fuel switching to coal since they are heavily oil and gas dominated.

3.1.5 Emission Control Devices

The emission control devices most commonly applied to the flue gas stream of a utility boiler burning coal are particulate collectors and SO_x scrubbers. However, application of scrubbing is still very limited. Flue gas denitrification devices have not been installed in this country. Their application has been limited to oil-fired boilers in Japan where NO_x emission standards are very stringent. This section discusses particulate and flue gas desulfurization (FGD) systems only. A discussion of flue gas denitrification systems under study for utility boilers is presented in Section 4.3.3 of this report. Control devices are rarely used in utility boiler liquid and solid effluents.

3.1.5.1 Particulate Emission Controls

Particulate emssions from coal fired utility boilers are generally controlled with centrifugal mechanical collectors or electrostatic precipitators (ESP). Centrifugal mechanical collectors, also called cyclones, are common on small and medium size utility boilers. Being of

TABLE 3-10. DISTRIBUTION OF REGIONAL UNCONTROLLED NO_x[a] EMISSIONS FROM COAL-FIRED UTILITY BOILERS IN 1974, (Percent) (Reference 3-32)

Equipment Type	New England	Middle Atlantic	E-N-Central	W-N-Central	South Atlantic	E-S-Central	W-S-Central	Mountain	Pacific	Total
Tangential	0.21	4.5	13.0	3.7	7.9	6.2	0.52	2.7	0.32	39
Single Wall	0.14	3.0	9.0	2.5	5.3	4.1	0.35	1.8	0.22	26
Opposed Wall[b]	0.039	0.87	2.6	0.71	1.5	1.2	0.10	0.52	0.062	7.6
Cyclone	0.042	2.8	8.2	2.3	4.8	3.8	0.32	1.7	0.20	24
Vertical and Stoker	0.014	0.29	0.86	0.24	0.51	0.4	0.033	0.18	0.022	2.5
Total	0.44	12	34	9.4	20	16	1.3	6.9	0.82	100

[a] NO_2 basis

[b] Includes turbo furnace

relatively simple design their initial cost is generally much smaller than ESPs. However, their collection efficiency is not as high as an ESP. Cyclone efficiencies can vary from 50 to 97 percent, based on the design of the device and the physical characteristics of the particulates in the flue gas.

Electrostatic precipitators (ESPs) of single stage design are commonly found on large size coal-fired boilers. The efficiencies of these ESPs can be as high as 99+ percent. However, the initial installation cost of these control devices can be very significant.

Several recent particulate studies (References 3-36 through 3-38) have provided information on the particulate controls installed on utility boilers. Twelve percent of pulverized coal-fired boilers have no collection devices. Table 3-11 lists the combined average collection efficiency of these devices. The data show that 35 percent of the flyash from pulverized coal-fired boilers, 25 percent of the flyash from cyclone boilers and 50 percent of the flyash from stokers are not collected.

TABLE 3-11. AVERAGE PARTICULATE COLLECTION FROM UTILITY BOILERS

Equipment/Fuel	Percent Collection
All/Pulverized Coal	65
Cyclone/Coal	75
Stoker/Coal	50
All/Residual Oil	25

3.1.5.2 Sulfur Oxides Emission Controls

There are many options under development for controlling SO_x emissions from coal-fired utility boilers. These include the use of solvent refined coal, dry limestone injection, direct firing of low sulfur coal, and flue gas desulfurization (FGD) via wet scrubbing. The latter two strategies are currently in active use and development. Where low sulfur coal is not available, flue gas desulfurization units may be needed to meet existing regulations. In addition, the recent promulgated (1979) SO_2 NSPS virtually require the use of FGD in new units. By 1979, about 65 units had been installed on U.S. electric utility boilers, serving an electric generation capacity of about 24,000 MW. Another 40 were under construction and about 75 were planned in utility plants producing a total of over 85,000 MW for all existing and planned installations. This is out of a total coal fueled capacity of 230,000 MW (Reference 3-39). Thus, the application of FGD is becoming more widespread.

Although a typical FGD system is expected to reduce SO_x emissions from a utility boiler by 80 to 95 percent, major problems remain. These include scaling, corrosion, and mist elimination, i.e. all problems of an operational or reliability nature (References 3-39 and 3-40).

Another area of serious concern to the utilities is the high cost of FGD systems. The most creditable cost estimates have been completed by the Tennessee Valley Authority (TVA) (Reference 3-41). TVA has updated its detailed cost estimates for EPA (Reference 3-42). Representative investment costs for an FGD system to remove 90 percent of SO_2 from a new 500 MW boiler fired with 3.5 percent sulfur in the coal range from \$60/kW to \$85/kW.

Average annual revenue requirements range from 3.4 to 5.4 mills/kWh (1977 costs). For perspective, a new coal-fired powerplant, operated without FGD is estimated to cost from \$400/kW to \$600/kW with a total cost of power of about 30 mills/kWh. It is evident that an FGD system would represent a significant portion of the cost of installing and operating a controlled plant. Thus, utilities are hesitant to apply FGD, unless absolutely necessary.

3.2 OIL-FIRED BOILERS

Oil accounted for 20 percent of the total fossil fuel consumed by utility boilers in 1977. This represented 34 percent of all the oil consumed by stationary combustion sources (Reference 3-2).

Although domestic oil production peaked in 1970, the demand for oil has continued to increase leading to an increased reliance on imported, more expensive petroleum (Reference 3-43). As a result, economic and political pressures have caused utilities to switch all new installations to coal firing. Thus, according to utility boiler manufacturers, no new oil-fired units have been purchased for the past 2 years and many previously ordered oil-fired units have been converted to coal firing during the design phase (References 3-44 through 3-48).

Since few new oil-fired units will be coming online in the future, and since there will be increasing impetus to switch existing units to coal firing, the present treatment of oil-fired utility boilers has been less comprehensive than that offered coal-fired units. Of course, many aspects of coal-fired utility boiler source characterization also hold true for oil-fired sources.

The following subsections describe oil-fired utility boiler equipment characterization, highlighting the differences between oil- and coal-fired boilers; utility boiler oil consumption; and oil-fired utility boiler emission factors. Expected trends in fuel consumption to the year 2000 are discussed and projected NO_x emissions are presented.

3.2.1 Typical Oil-Fired Boilers

Major types of oil-fired boilers are similar to those firing coal. However, vertical and stoker fired boilers are not used to burn oil. Thus, tangential, single wall, horizontally opposed, turbo and cyclone furnaces are the only equipment firing types burning petroleum fuels.

Oil-fired boilers are more compact than coal-fired boilers of the same heat input. The principle reason is that coal particles require longer residence times for complete combustion in the furnace. Furthermore, because the relatively low ash content of oil precludes slagging on the cooling walls, oil-fired boilers can have smaller fireboxes than coal-fired boilers.

Similarly, since the combustion gases contain less flyash, the convective section of oil-fired boilers can be more compact, with more closely spaced tubes. Finally, oil-fired boilers operate at lower excess air levels than coal-fired units; up to 20 percent less air volume per unit heat input is required for oil firing (Reference 3-49).

The more compact design of oil-fired furnaces often can cause NO_x emissions to be as high as those from coal combustion even though the nitrogen content of the oil is generally lower than that of coal. The lower heat flux to furnace walls creates a higher temperature flame which causes large quantities of thermal NO_x to be formed. The thermal NO_x contribution more than offsets the lower fuel NO_x contribution of the cleaner oil fuels.

Single wall and tangentially fired boilers consume the most fuel oil among the design types. Each consumes about 8 percent of the total fossil fuel consumed by utility boilers. The burners on single wall and horizontally opposed units are usually register burners with capacities in the 22 MW (~75 MBtu/hr) to 48 MW (~165 MBtu/hr) heat input range. Up to 72 burners can be mounted on the furnace walls. Residual oil is preheated and injected through atomizers, usually using high pressure steam, though air and mechanical atomizers are occasionally used (Reference 3-50). Distillate oils are not preheated.

Cyclone furnaces represent the only minor design type burning petroleum fuel. Oil burned in cyclone boilers accounted for only 5 percent of all fuels burned in this boiler type in 1977 (Reference 3-2). Since cyclone boilers are high NO_x emitters and fuel oil is becoming increasingly scarce, it is expected that cyclone oil-fired boilers will be even less prevalent in the future.

3.2.2 Oil Consumption

Table 3-12 shows the percentage of oil consumed for each firing type in 1977 (Reference 3-2) and projects consumption up to the year 2000. A major shift from oil-firing to coal-firing is expected to decrease oil consumption by the year 1985. The Powerplant and Industrial Fuel Use Act of 1978 will greatly limit growth of oil consumption in utility boilers throughout the century . No difference in oil consumption is expected between the low nuclear and high nuclear scenarios because coal will fill the utilities' fossil fuel demand if nuclear power generation is restricted. Percent values for Table 3-12 were calculated using the total fuel consumed by the utilities for both energy scenarios.

Many uncertainties make oil consumption difficult to predict. For example, changes in import prices and supply can cause major changes in oil consumption. The development of oil from the Outer Continental Shelf and Alaska will have national as well as regional effects on the oil supply. Since domestic supplies of petroleum are limited, means are being sought to reduce liquid fuel consumption and increase its synthesis from other sources. The technical and economic feasibility of several of these synthesis processes remains to be demonstrated.

TABLE 3-12. UTILITY OIL CONSUMPTION BY EQUIPMENT TYPE, (EJ/yr)
(Reference 3-2)

Year	1977	1985	2000	
Equipment Type			High Nuclear	Low Nuclear
Tangential	1.6 (7.7)[a]	1.4 (5.5)	1.4 (2.9)	1.4 (2.0)
Single Wall	1.8 (8.6)	1.6 (6.3)	1.6 (3.4)	1.6 (2.3)
Opposed Wall and Turbo Furnace	0.63 (3.0)	0.58 (2.3)	0.58 (1.2)	0.58 (0.83)
Cyclone	0.08 (0.36)	0.067 (0.26)	0.044 (0.092)	0.044 (0.063)

[a] Percent of total fuel used by utilities is given in parentheses

Petroleum fuels, like coals, are heterogeneous fuels whose chemical contaminants, sulfur, nitrogen, and trace metals, vary significantly among regions. Petroleum fuels for utility boilers can be distinguished as follows:

- Residual fuel oil
    - -- Interior Province (high sulfur) -- 2.8 percent (S)
    - -- Eastern Province (medium sulfur) -- 2.2 percent (S)
    - -- Western Province (low sulfur) -- 1.6 percent (S)
- Distillate fuel oil -- 0.25 percent (S)

Table 3-13 presents the trend in utility petroleum consumption of these different oil types. Medium and low sulfur oils will continue to dominate the utility market to the year 2000, followed by high sulfur residual and distillate oils. The percentage consumption values for these fuels are shown in parentheses in the table.

TABLE 3-13. UTILITY OIL FUEL CONSUMPTION BY TYPE,
(EJ/yr) (Reference 3-2)

Year	1977	1985	2000	
Oil Type			High Nuclear	Low Nuclear
High Sulfur Residual and Crude	0.54 (2.6)[a]	0.48 (1.9)	0.48 (2.1)	0.48 (0.69)
Medium Sulfur Residual and Crude	1.3 (6.4)	1.2 (4.7)	1.2 (2.5)	1.2 (1.7)
Low Sulfur Residual and Crude	1.7 (8.3)	1.5 (5.9)	1.5 (3.2)	1.5 (2.2)
Distillate	0.49 (2.4)	0.42 (1.6)	0.42 (0.88)	0.42 (0.60)

[a] Percent of total fuel consumed by utilities is given in parentheses.

Table 3-14 shows the regional oil consumption for 1974 by the different boiler firing types. The South Atlantic region shows the highest oil consumed with Middle Atlantic, Pacific, and New England regions following close behind.

3.2.3 NO_x Emissions Inventory

The emissions from oil-fired utility boilers are listed in Table 3-15. Single wall and tangential fired boilers produce more NO_x than all other types of oil-fired utility boilers. In 1977, NO_x contribution by oil-fired single wall and tangential boilers amounted to 82 percent of the total NO_x emissions from all oil-fired boilers. Their contribution is expected to remain relatively the same throughout the remainder of the century.

TABLE 3-14. REGIONAL OIL CONSUMPTION BY EQUIPMENT TYPE IN 1974, (Percent) (Reference 3-32)

Equipment Type	New England	Middle Atlantic	E-N-Central	W-N-Central	South Atlantic	E-S-Central	W-S-Central	Mountain	Pacific	Total
Tangential	5.8	10.4	2.0	0.3	12	0.71	1.7	0.84	6.0	39
Single Wall	6.3	12	2.1	0.3	13	0.78	1.8	0.92	6.5	43
Opposed Wall	2.3	4.2	0.79	0.1	4.6	0.29	0.68	0.34	2.4	16
Cyclone	0.32	0.59	0.11	--	0.65	0.04	0.10	0.049	0.34	2.2
Total	15	27	5.0	0.7	29	1.8	4.3	2.2	15	100

TABLE 3-15. NO_x EMISSIONS FROM OIL-FIRED UTILITY BOILERS, (Gg/yr) (Reference 3-2)

Year	1977	1985	2000	
Equipment Type			High Nuclear	Low Nuclear
Tangential	200 (3.4)[a]	180 (2.5)	180 (2.1)	180 (1.6)
Single Wall	330 (5.6)	280 (3.8)	280 (3.2)	280 (2.6)
Opposed Wall Turbo Furnace	98 (1.6)	90 (1.2)	90 (1.0)	90 (0.82)
Cyclone	20 (0.34)	17 (0.23)	11 (0.12)	11 (0.01)

[a] Percent of total NO_x from all utility boilers is given in parentheses

Table 3-16 shows how NO_x emissions are partitioned in each of the nine Census Bureau regions. In conjunction with regional fuel consumption data, NO_x emissions for oil combustion are highest in Pacific and Eastern Continental regions (New England, Middle and South Atlantic).

3.3 GAS-FIRED BOILERS

Natural gas accounted for 23 percent of the total fossil fuel consumed by utility boilers in 1977, or 28 percent of the total gas consumed by all stationary sources. As in the case of petroleum fuels, natural gas will diminish as a fuel for utility steam generators as utilities will switch to oil or coal.

The following subsections highlight the main differences between gas-fired boilers and boilers burning other fuels. Natural gas consumption

TABLE 3-16. REGIONAL UNCONTROLLED NO_x[a] EMISSIONS FROM OIL-FIRED UTILITY BOILERS IN 1974, (Percent) (Reference 3-32)

Equipment Type	New England	Middle Atlantic	E-N-Central	W-N-Central	South Atlantic	E-S-Central	W-S-Central	Mountain	Pacific	Total
Tangential	3.5	6.3	1.2	0.16	6.9	0.34	1.0	0.51	3.6	24
Single Wall	8.0	15	2.7	0.35	16	0.98	2.4	1.2	8.3	55
Opposed Wall	7.0	4.2	0.99	0.14	4.2	0.36	0.87	0.43	1.9	20
Cyclone	0.28	0.51	0.09	0.011	0.56	0.034	0.079	0.045	0.29	1.9
Total	19	26	5.0	0.66	27	1.7	4.4	2.2	14	100

[a] NO_2 basis

is discussed in Section 3.3.2 and NO_x emissions from gas-fired utility boilers are summarized in Section 3.3.3.

3.3.1 Typical Gas-Fired Boilers

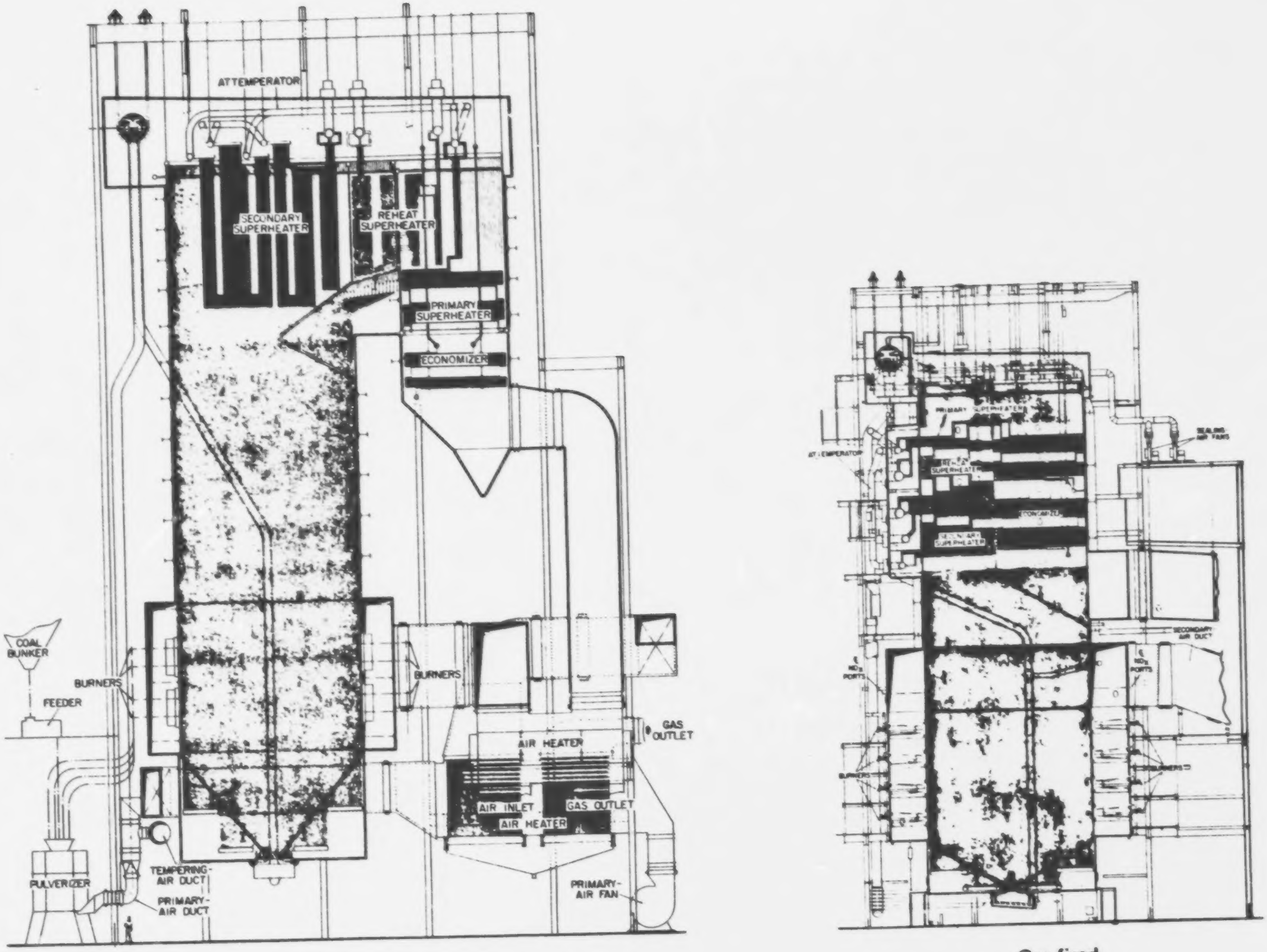
Gas-fired boilers are quite similar in design to oil-fired boilers. In fact, most gas-fired boilers were designed to fire oil as a supplementary fuel. Those designed strictly for gas firing differ mainly in size. Primarily gas-fired boilers are the most compact of all steam generators due to the rapid combustion of the gaseous fuel, the low flame luminosity, and the ash free content of natural gas. Figure 3-7 illustrates the sizes of two utility boilers -- one coal fired and one gas fired -- with the same heat input.

Because a constant supply of natural gas is difficult to maintain, gas-fired generators are usually equipped to burn oil too. The oil burning equipment allows plants to switch to petroleum fuels anytime the natural gas supply is curtailed. Thus, these steam generators are not designed as compactly as they could be if only natural gas were burned.

Since natural gas contains no fuel bound nitrogen, no fuel NO_x is produced by its combustion. However, the high volumetric heat release rates caused by small furnaces in gas-fired boilers can result in high thermal NO_x formation. Section 4 will show that uncontrolled NO_x emissions from gas-fired boilers can be higher at times than emissions from oil- or coal-fired boilers.

3.3.2 Natural Gas Consumption

Table 3-17 shows past and projected future natural gas consumption for each type of boiler. Single wall fired boilers are the most common type of gas burning equipment, followed by horizontally opposed and tangential boilers. In 1977, single wall fired boilers burned 50 percent of all natural gas used by the utilities. Tangential and horizontally opposed fired boilers consumed most of the remaining 50 percent. It is estimated that natural gas consumption by the utilities will decrease by over one-third from 1977 to 1985 and remain roughly constant after that. Overall, natural gas represented almost 23 percent of all the fuel consumed by utility boilers in 1977. By 1985, natural gas will represent only 12 percent of all fuels.


ATTEMPERATOR
SECONDARY SUPERHEATER
REHEAT SUPERHEATER
PRIMARY SUPERHEATER
ECONOMIZER
COAL BUNKER
BURNERS
FEEDER
BURNERS
GAS OUTLET
AIR HEATER
AIR INLET
GAS OUTLET
AIR HEATER
PULVERIZER
TEMPERING-AIR DUCT
PRIMARY-AIR DUCT
PRIMARY-AIR FAN
PRIMARY SUPERHEATER
ATTEMPERATOR
REHEAT SUPERHEATER
ECONOMIZER
SECONDARY SUPERHEATER
SEALING AIR FANS
SECONDARY AIR DUCT
NOx PORTS
NOx PORTS
BURNERS
BURNERS

Coal fired

Gas fired

Figure 3-7. Size comparison between coal- and gas-fired steam generators of the same rating (Reference 3-49)

TABLE 3-17. UTILITY GAS CONSUMPTION, (EJ/yr) (Reference 3-2)

Year	1977	1985	2000	
Equipment Type			High Nuclear	Low Nuclear
Tangential	1.1 (5.3)[a]	0.68 (2.6)	0.68 (1.4)	0.68 (0.98)
Single Wall	2.4 (12.0)	1.5 (5.7)	1.5 (3.2)	1.5 (2.2)
Opposed Wall and Turbo Furnace	1.2 (5.9)	0.75 (2.9)	0.75 (1.6)	0.75 (1.1)
Cyclone	0.078 (0.37)	0.066 (0.26)	0.042 (0.088)	0.042 (0.06)

[a] Percent of total fuel consumed by utilities is given in parentheses

The accuracy of these fuel consumption data depends on numerous factors. For example, although a proposed pipeline to deliver gas from Alaska in the mid-1980's will increase production temporarily, production will decline rapidly after this source is exhausted unless recovery and extensive offshore development can be pursued. Unfortunately, development of offshore gas fields is not considered to be economical at today's regulated prices. However, if price controls on interstate natural gas are eliminated, impetus for further development and gas production may result. In addition to the uncertainty concerning deregulation, technology for the development of alternative synthetic gas is questionable. This will affect the supply of gas since the projected shortfall in gas supplies in the 1980's will most likely have to be made up by synthetic gas, primarily from coal.

Table 3-18 lists the regional distribution of natural gas consumed by utility boilers in 1974. Natural gas consumed in the West South Central region accounts for over 60 percent of all gas consumed nationally. Natural gas consumption is significant also in West North Central, Pacific, South Atlantic, and Mountain regions.

3.3.3 NO_x Emissions Inventory

NO_x emissions from gas-fired utility boilers by equipment type are listed in Table 3-19. In 1977 emissions from gas-fired utility boilers accounted for 12 percent of all NO_x produced by the utilities. By 1985 emissions will account for only 6 percent of the total NO_x produced by the utilities. The predicted reduction of NO_x emitted from all gas-fired boilers is estimated due primarily to a 38 percent decrease in gas consumption. Table 3-20 shows how NO_x emissions from gas-fired boilers are partitioned between the nine Census Bureau regions. The West South Central region accounted for the most NO_x from natural gas combustion. New England accounted for the least.

TABLE 3-18. REGIONAL NATURAL GAS CONSUMPTION BY UTILITY BOILERS IN 1974, (Percent) (Reference 3-2)

Equipment Type	New England	Middle Atlantic	E-N-Central	W-N-Central	South Atlantic	E-S-Central	W-S-Central	Mountain	Pacific	Total
Tangential	0.065	0.30	0.81	2.4	1.5	0.34	14	1.4	2.1	23
Single Wall	0.14	0.65	1.8	5.1	3.2	0.74	31	3.0	4.5	50
Opposed Wall	0.15	0.33	0.90	2.6	1.6	0.38	16	1.5	2.3	26
Cyclone	0.004	0.016	0.045	0.13	0.079	0.018	0.77	0.073	0.11	1.2
Total	0.36	1.3	3.5	10	6.4	1.5	62	6.0	9.0	100

TABLE 3-19. NO_x EMISSIONS FROM GAS-FIRED UTILITY BOILERS, (Gg/yr) (Reference 3-2)

Year	1977	1985	2000	
Equipment Type			High Nuclear	Low Nuclear
Tangential	100 (1.7)[a]	66 (0.91)	66 (0.76)	66 (0.60)
Single Wall	310 (5.2)	180 (2.5)	180 (2.1)	180 (1.6)
Opposed Wall and Turbo Furnace	260 (4.4)	140 (1.9)	140 (1.6)	140 (1.3)
Cyclone	19 (0.32)	16 (0.22)	10 (0.12)	10 (0.091)

[a] Percent of total NO_x from utility boilers is given in parentheses

TABLE 3-20. DISTRIBUTION OF REGIONAL UNCONTROLLED NO_x[a] EMISSIONS FROM GAS-FIRED UTILITY BOILERS IN 1974, (Percent) (Reference 3-32)

Equipment Type	New England	Middle Atlantic	E-N-Central	W-N-Central	South Atlantic	E-S-Central	W-S-Central	Mountain	Pacific	Total
Tangential	0.03	0.15	0.40	1.2	0.74	0.17	7.1	0.68	1.0	12
Single Wall	0.16	0.75	2.0	5.9	3.7	0.85	36	3.4	5.2	58
Opposed Wall	0.17	0.38	1.0	3.0	1.9	0.44	18	1.8	2.7	30
Cyclone	0.008	0.016	0.039	0.12	0.07	0.016	0.71	0.07	0.1	1.2
Total	0.37	1.3	3.4	10	6.4	1.5	62	6.0	9.0	100

T-845

[a] NO_2 basis

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SECTION 4

OVERVIEW OF NO_x CONTROL TECHNOLOGY

Modifying the combustion process conditions is the most effective and widely used technique for achieving moderate (20 to 60 percent) reduction in combustion generated oxides of nitrogen. This section reviews the combustion modification techniques either demonstrated or currently under development. The review begins with a discussion of the formation mechanisms of NO_x and the general principles for suppressing NO_x emissions by process modifications.

4.1 GENERAL CONCEPTS ON NO_x FORMATION AND CONTROL

Oxides of nitrogen formed in combustion processes are due either to the thermal fixation of atmospheric nitrogen in the combustion air, which produces "thermal NO_x," or to the conversion of chemically bound nitrogen in the fuel, which produces "fuel NO_x." For natural gas and light distillate oil firing, nearly all NO_x emissions result from thermal fixation. With residual oil, crude oil, and coal, the contribution from fuel bound nitrogen can be significant and, in certain cases, predominant.

4.1.1 Thermal NO_x

During combustion, nitrogen oxides are formed by the high temperature, thermal fixation of N_2. Nitric oxide (NO) is the major product, even though NO_2 is thermodynamically favored at lower temperatures. The residence time in most stationary combustion processes is too short for significant NO to be oxidized to NO_2.

The detailed chemical mechanism for thermal NO_x formation is not fully understood. However, it is widely accepted that thermal fixation in the postcombustion zone occurs according to the extended form of the Zeldovich chain mechanism (Reference 4-1):

$$N_2 + O \rightleftarrows NO + N \tag{4-1}$$

$$N + O_2 \rightleftarrows NO + O \tag{4-2}$$

$$N + OH \rightleftarrows NO + H \tag{4-3}$$

assuming that the combustion reactions have reached equilibrium. Reaction (4-1) has a large activation energy (317 kJ/mol) and is generally believed to be rate determining. Oxygen atom concentrations are assumed to have reached equilibrium according to:

$$O_2 + M \rightleftarrows O + O + M \tag{4-4}$$

where M denotes any third substance (usually N_2).

In the flame zone itself, the Zeldovich mechanism with the equilibrium oxygen assumption is not adequate to account for experimentally observed NO formation rates. Several investigators have observed the production of significant amounts of "prompt" NO, which is formed very rapidly in the flame front (References 4-2 through 4-10), but there is no general agreement on how it is produced. Prompt NO is believed to stem from the existence of "superequilibrium" radical concentrations (References 4-10, 4-11, and 4-12) within the flame zonewhich result from hydrocarbon chemistry and/or nitrogen specie reactions, such as suggested by Fenimore (Reference 4-13). To date, prompt NO has only been explicitly measured in carefully controlled laminar flames, but the mechanism almost certainly exists in typical combustor flames as well. Of course, in an actual combustor, both the hydrocarbon and NO_x kinetics are directly coupled to turbulent mixing in the flame zone.

Recent experiments at atmospheric pressure indicate that under certain conditions the amount of NO formed in heated N_2, O_2, and Ar mixtures can be expressed as (Reference 4-14):

$$[NO] = k_1 \exp(-k_2/T)[N_2][O_2]^{1/2}t \tag{4-5}$$

where $[\ ]$ = mole fraction

k_1, k_2 = constants

T = temperature

t = time

Although this expression certainly will not adequately describe NO formation in a turbulent flame, it does point out several features of thermal NO_x formation. It reflects the strong dependence of NO formation on temperature. It also shows that NO formation is directly proportional to N_2 concentration and to residence time, and proportional to the square root of oxygen concentration.

Based on the above relations, thermal NO_x can theoretically be reduced using four tactics:

- Reduce local nitrogen concentrations at peak temperature
- Reduce local oxygen concentrations at peak temperature
- Reduce the residence time at peak temperature
- Reduce peak temperature

Since reducing N_2 levels is quite difficult, efforts in the field have focused on reducing oxygen levels, peak temperatures, and time of exposure in the NO_x producing regions of a furnace. On a macroscopic scale, techniques such as lowered excess air and off stoichiometric (or staged) combustion have been used to lower local O_2 concentrations in utility boilers. Similarly, flue gas recirculation and reduced air preheat have been used in boilers to control thermal NO_x by lowering peak flame temperatures. Flue gas recirculation also reduces combustion gas residence time, but its primary effect as a thermal NO_x control is through temperature reduction.

It is important to recognize that the above-mentioned techniques for thermal NO_x reduction alter combustion conditions on a macroscopic scale. Although these macroscopic techniques have all been relatively successful in reducing thermal NO_x, local microscopic combustion conditions ultimately determine the amount of thermal NO_x formed. These conditions are in turn intimately related to such variables as local combustion intensity, heat removal rates, and internal mixing effects. Modifying these secondary combustion variables at microscopic levels requires fundamantal changes in combustion equipment design.

For example, recent studies on the formation of thermal NO_x in gaseous flames have confirmed that internal mixing can have large effects on the total amount of NO formed (References 4-15, 4-16). Burner swirl, combustion air velocity, fuel injection angle and velocity, quarl angle, and confinement ratio all affect the mixing between fuel, combustion air, and recirculated products. Mixing, in turn, alters the local temperatures and specie concentrations which control the rate of NO_x formation.

Unfortunately, generalizing these effects is difficult, because the interactions are complex. Increasing swirl, for example, may both increase entrainment of cooled combustion products (hence lowering peak temperatures) and increase fuel/air mixing (raising local combustion intensity). The net effect of increasing swirl can be to either raise or lower NO_x emissions, depending on other system parameters.

In summary, a hierarchy of effects depicted in Table 4-1 produces local combustion conditions which promote thermal NO_x formation. Although combustion modificiation technology seeks to affect the fundamental parameters of combustion, modifications must be made by changing the primary equipment and fuel parameters. Control of thermal NO_x, which began by altering inlet conditions and external mass addition, has moved to more fundamental changes in combustion equipment design.

4.1.2 Fuel NO_x

The role of fuel bound nitrogen as a source of NO_x emissions from combustion sources has been recognized since 1968 (Reference 4-17). Although the relative contribution of fuel and thermal NO_x to total NO_x emissions from sources firing nitrogen containing fuels has not been definitively established, recent estimates indicate that fuel NO_x is significant and may even predominate. In one laboratory study (Reference 4-18), residual oil and pulverized coal were burned in an argon/oxygen mixture to eliminate thermal NO_x effects. Results show that fuel NO_x can account for over 50 percent of total NO_x production from residual oil firing and approximately 80 percent of total NO_x from coal firing. Tests on a full scale system, a 560 MW coal-fired utility boiler, confirm this prediction (Reference 4-19). Flue gas recirculation, which controls primarily thermal NO_x, was a relatively ineffective NO_x control measure for the coal-fired boiler tested.

TABLE 4-1. FACTORS CONTROLLING THE FORMATION OF THERMAL NO_x

Primary Equipment and Fuel Parameters	Secondary Combustion Parameters	Fundamental Parameters	
Inlet temperature, velocity Firebox design Fuel composition Injection pattern of fuel and air Size of droplets or particles Burner swirl External mass addition	Combustion intensity Heat removal rate Mixing of combustion products into flame Local fuel/air ratio Turbulent distortion of flame zone	Oxygen level Peak temp. Exposure time at peak temp.	Thermal NO_x

Fuel bound nitrogen occurs in coal and petroleum fuels. However, the nitrogen containing compounds in petroleum tend to concentrate in the heavy resin and asphalt fractions upon distillation (Reference 4-20). Therefore fuel NO_x is of importance primarily in residual oil and coal firing. The nitrogen compounds found in petroleum include pyrroles, indoles, isoquinolines, acridines, and porphyrins. Although the structure of coal has not been defined with certainty, it is believed that coal-bound nitrogen also occurs in aromatic ring structures such as pyridine, picoline, quinoline, and nicotine (Reference 4-20).

The nitrogen content of residual oil varies from 0.1 to 0.5 percent. Nitrogen content of most U.S. coals lies in the 0.5 to 2 percent range (Reference 4-21); anthracite coals contain the least and bituminous coals the most nitrogen. Figure 4-1 illustrates the nitrogen content of various U.S. coals, expressed at ng NO_2 produced per joule for 100 percent conversion of the fuel nitrogen (Reference 4-22). The figure clearly shows that if all coal bound nitrogen were converted to NO_x, emissions for all

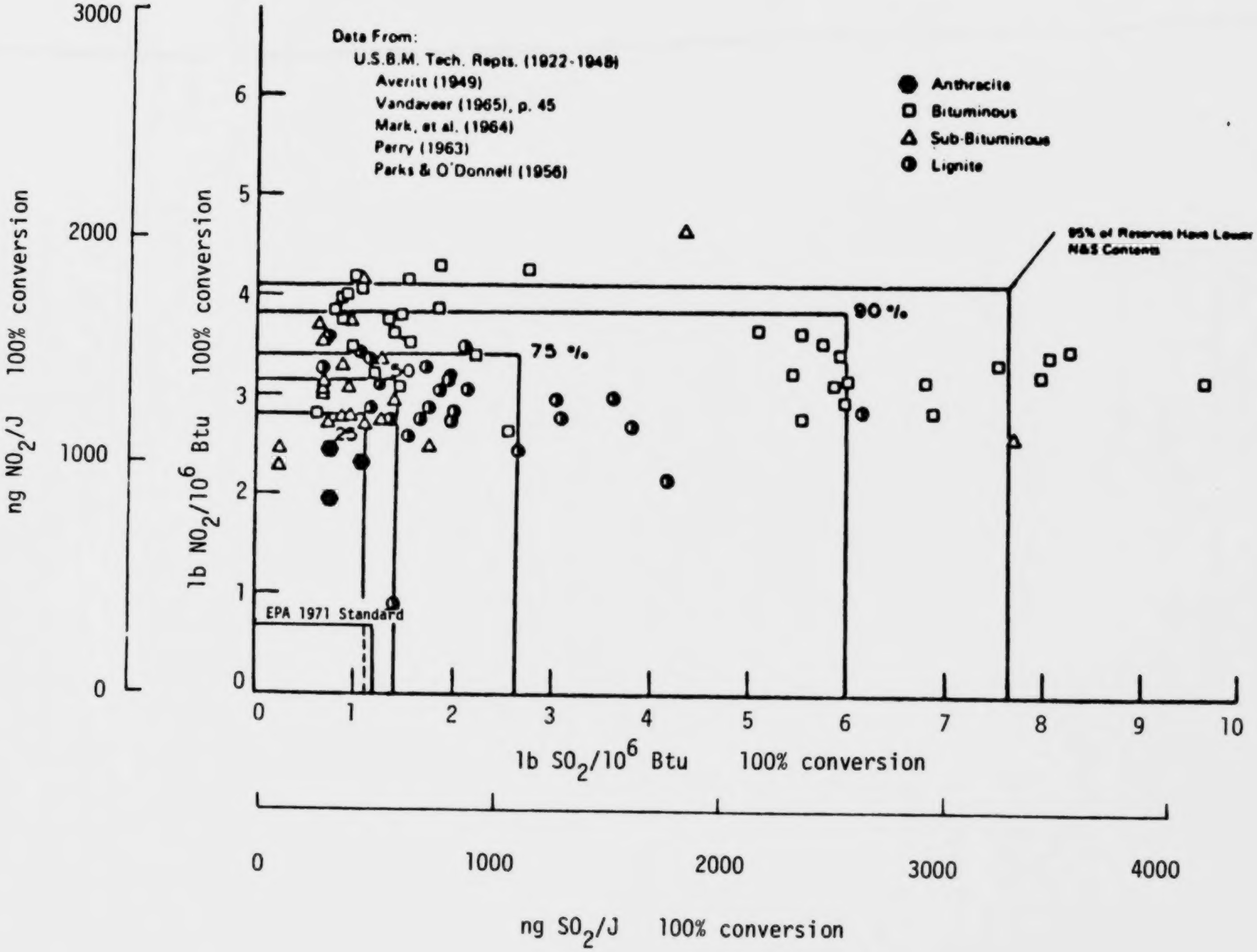


Figure 4-1. Nitrogen and sulfur content of U.S. coal reserves (Reference 4-21).

coals would exceed even the 1971 Standards of Performance for Large Steam Generators (NSPS). Fortunately, only a fraction of the fuel nitrogen is converted to NO_x for both oil and coal firing, as shown in Figure 4-2 (Reference 4-23). Furthermore, the figure indicates that fuel nitrogen conversion decreases as nitrogen content increases. Thus, although fuel NO_x emissions undoubtedly increase with increasing fuel nitrogen content, the emissions increase is not proportional. In fact, recent data indicate only a small increase in NO_x emissions as fuel nitrogen increases (Reference 4-24). From observations such as these, the effectiveness of partial fuel denitrification as a NO_x control method seems doubtful.

Although the precise mechanism by which fuel nitrogen is converted to NO_x is not understood, certain aspects are clear, particularly for coal combustion. In a large pulverized coal-fired utility boiler, the coal particles are conveyed by an airstream into the hot combustion chamber, where they are heated at a rate in excess of 10^4 K/s. Almost immediately volatile species, containing some of the coal bound nitrogen, vaporize and burn homogeneously, rapidly (~10 ms) and probably detached from the original coal particle. Combustion of the remaining solid char is heterogeneous and much slower (~300 ms).

Figure 4-3 summarizes what may happen to fuel nitrogen during this process (Reference 4-25). In general, nitrogen evolution parallels evolution of the total volatiles, except during the initial 10 to 15 percent volatilization in which little nitrogen is released (Reference 4-26). Both total mass volatilized and total nitrogen volatilized increase with higher pyrolysis temperature; the nitrogen volatilization increases more rapidly than that of the total mass. Total mass volatilized appears to be a stronger function of coal composition than total nitrogen volatilized (Reference 4-27). This supports the relatively small dependence of fuel NO_x on coal composition observed in small scale testing (References 4-18 and 4-28).

Although there is not absolute agreement on how the volatiles separate into species, it appears that about half the total volatiles and 85 percent of the nitrogeneous species evolved react to form other reduced species before being oxidized. Prior to oxidation, the devolatilized nitrogen may be converted to a small number of common, reduced

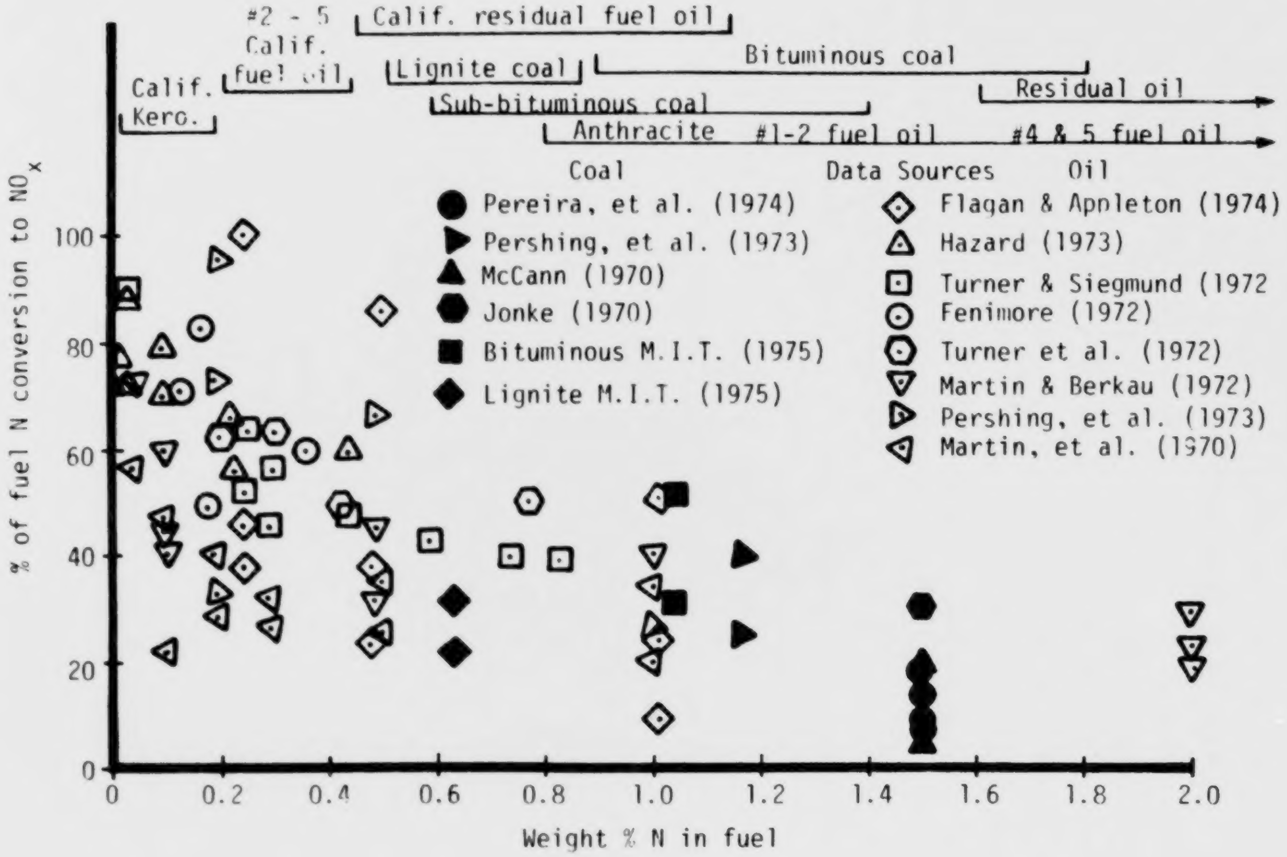


Figure 4-2. Conversion of fuel N in practical combustors (Reference 4-22).

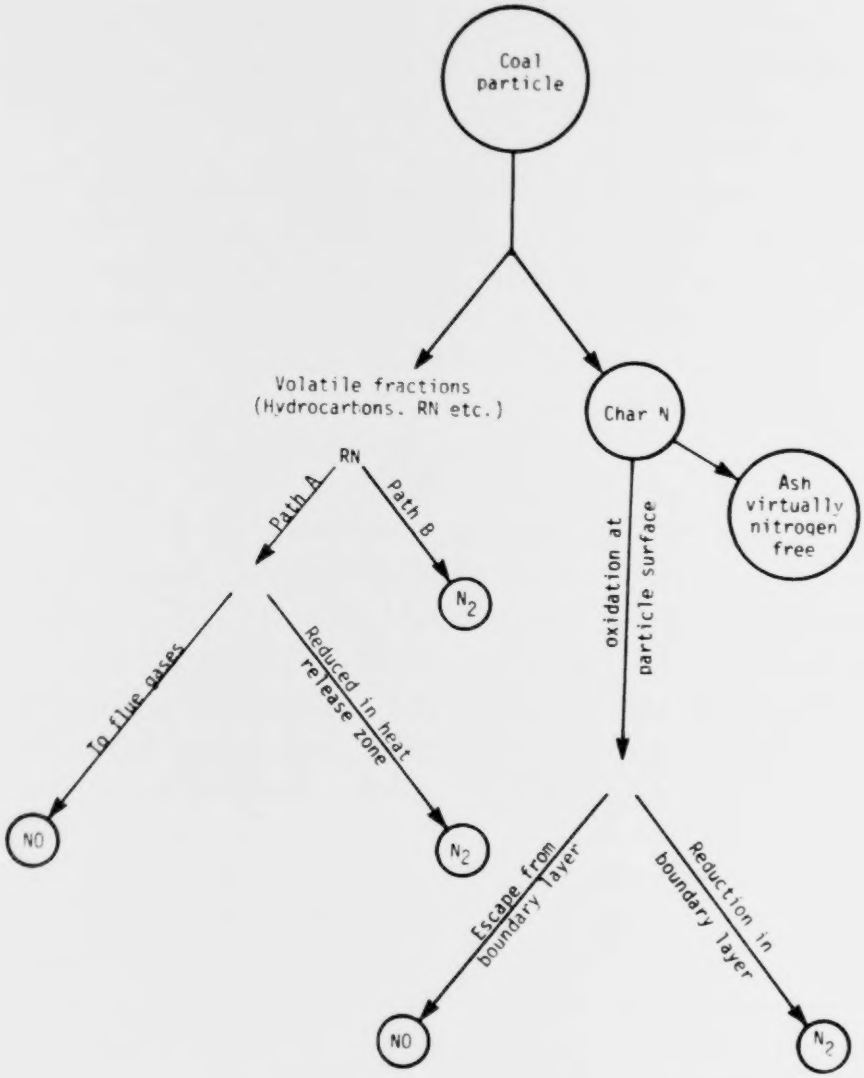

Coal particle
Volatile fractions (Hydrocarbons. RN etc.)
RN
Path A
Path B
N_2
To flue gases
Reduced in heat release zone
NO
N_2
Char N
Ash virtually nitrogen free
oxidation at particle surface
Escape from boundary layer
Reduction in boundary layer
NO
N_2

Figure 4-3. Possible fate of fuel nitrogen contained in coal particles during combustion (Reference 4-25).

intermediates, such as HCN and NH_3, in the fuel-rich regions of the flames. The existence of a set of common reduced intermediates would explain the observations that the form of the original fuel nitrogen compound does not influence its conversion to NO (e.g., References 4-20, 4-29). More recent experiments suggest that HCN is the predominant reduced intermediate (Reference 4-30). The reduced intermediates are then either oxidized to NO, or converted to N_2 in the postcombustion zone. Although the mechanism for these conversions is not presently known, one proposed mechanism postulates a role for NCO (Reference 4-31).

Nitrogen retained in the char may also be oxidized to NO, or reduced to N_2 through heterogeneous reactions occurring in the postcombustion zone. However, it is clear that the conversion of char nitrogen to NO proceeds much more slowly than the conversion of devolatilized nitrogen. In fact, based on a combination of experimental and empirical modeling studies, it is now believed that 60 to 80 percent of the fuel NO_x results from volatile nitrogen oxidation (References 4-26, 4-32). Conversion of the char nitrogen to NO is in general lower, by factors of two to three, than conversion of total coal nitrogen (Reference 4-29).

Regardless of the precise mechanism of fuel NO_x formation, several general trends are evident, particularly for coal combustion. As expected, fuel nitrogen conversion to NO is highly dependent on the fuel/air ratio for the range existing in typical combustion equipment, as shown in Figure 4-4. Oxidation of the char nitrogen is relatively insensitive to fuel/air changes, but volatile NO formation is strongly affected by fuel/air ratio changes.

In contrast to thermal NO_x, fuel NO_x production is relatively insensitive to small changes in combustion zone temperature (Reference 4-29). Char nitrogen oxidation appears to be a very weak function of temperature, and although the amount of nitrogen volatiles appears to increase as temperature increases, this is believed to be partially offset by a decrease in percentage conversion. Furthermore, operating restrictions severely limit the magnitude of actual temperature changes attainable in current systems.

As described above, fuel NO_x emissions are a strong function of fuel/air mixing. In general, any change which increases the mixing between the fuel and air during coal devolatilization will dramatically increase

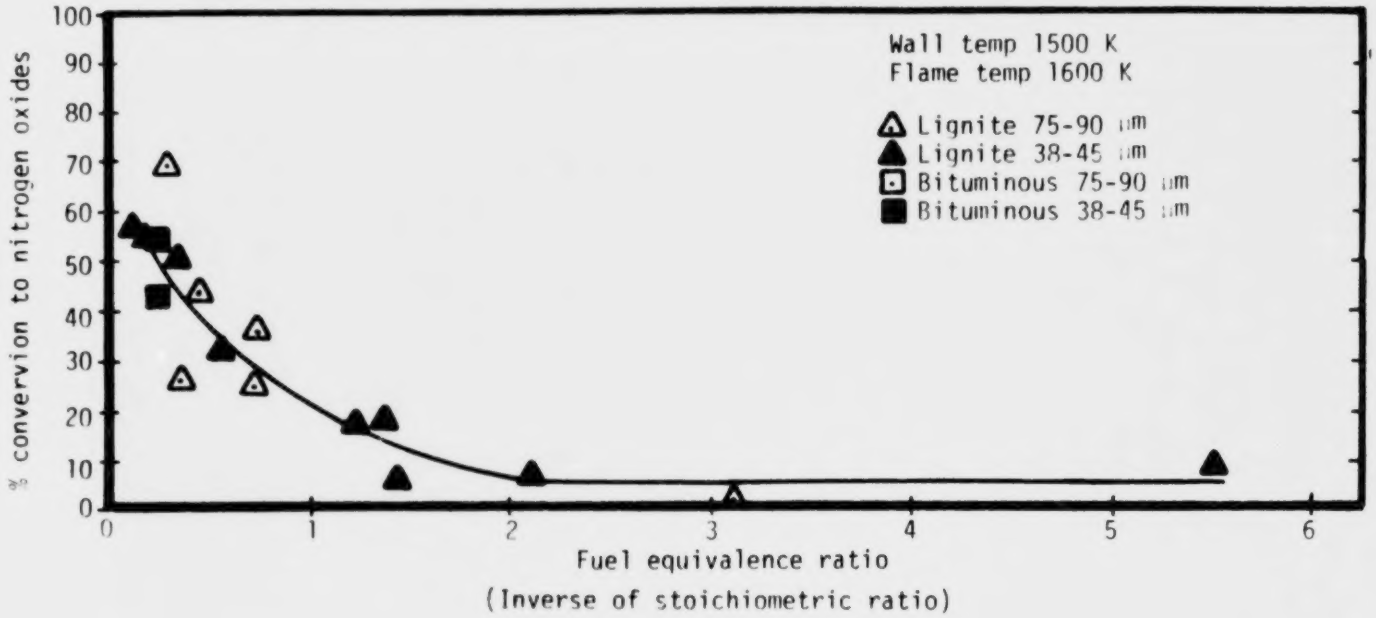


Figure 4-4. Conversion of nitrogen in coal to NO_x (Reference 4-23).

volatile nitrogen conversion and increase fuel NO_x. In contrast, char NO formation is only weakly dependent on initial mixing.

From the above modifications, it appears that, in principle, the best strategy for fuel NO_x abatement combines low excess air (LEA) firing, optimum burner design, and two stage combustion. Assuming suitable stage separation, low excess air may have little effect on fuel NO_x, but it increases system efficiency. Before using LEA firing, the need to get good carbon burnout and low CO emissions must be considered.

Optimum burner design ensures locally fuel-rich conditions during devolatilization, which promotes reduction of devolatilized nitrogen to N_2. Two-stage combustion produces overall fuel-rich conditions during the first 1 to 2 seconds and promotes the reduction of NO to N_2 through reburning reactions. High secondary air preheat may also be desirable, because it promotes more complete nitrogen devolatilization in the fuel-rich initial combustion stage. This leaves less char nitrogen to be subsequently oxidized in the fuel-lean second stage. Unfortunately, it also tends to favor thermal NO formation, and at present there is no general agreement on which effect dominates.

4.1.3 Summary of Process Modification Concepts

In summary of the above discussion, both thermal and fuel NO_x are kinetically or aerodynamically limited in that their emission rates are far below the levels which would prevail at equilibrium. Thus, the rate of formation of both thermal and fuel NO_x is dominated by combustion conditions and is amenable to suppression through combustion process modifications. Although the mechanisms are different, both thermal and fuel NO_x are promoted by rapid mixing of oxygen with the fuel. Additionally, thermal NO_x is greatly increased by long residence time at high temperature. The modified combustion conditions and control concepts which have been tried or suggested to combat the formation mechanisms are as follows:

- Decrease primary flame zone O_2 level by
    - -- Decreased overall O_2 level
    - -- Controlled mixing of fuel and air
    - -- Use of fuel-rich primary flame zone

- Decrease time of exposure at high temperature by
  - Decreased peak temperature:
    - Decreased adiabatic flame temperature through dilution
    - Decreased combustion intensity
    - Increased flame cooling
    - Controlled mixing of fuel and air or use of fuel-rich primary flame zone
  - Decreased primary flame zone residence time
- Chemically reduce NO_x in postflame region by
  - Injection of reducing agent (e.g., NH_3)

Table 4-2 relates these control concepts to combustion process modifications applicable to utility boilers. The process modifications are categorized according to their role in the control development sequence: operational adjustments, hardware modifications of existing equipment or through factory installed controls, and major redesigns of new equipment. The controls for decreased O_2 are also generally effective for peak temperature reduction but have not been repeated. The following subsections briefly review the status of each of the applicable control techniques applied to utility boilers.

4.2 STATE-OF-THE-ART CONTROLS

Based on the general principles discussed above for the suppression of NO_x emissions by process modifications, there are several control techniques that may be used singly or conjunctively on utility boilers. These techniques include low excess air firing, biased burner firing, burners out of service, overfire air, low NO_x burners, flue gas recirculation, and reduced firing rate. These methods for controlling NO_x may be used on existing boilers although modifications to the units may be required. Tables 4-3 through 4-10 give the average NO_x reduction achievable with the various control techniques, compiled from the data base of test results and test selection procedures discussed in Section 5. It should be noted that the data base is not complete in that only those tests that were well characterized are included; i.e., such boiler design and operating variables as number of burners, burner stoichiometry, direct input per active burner, surface heat release rate, etc., were reported (see Section 5.2.2).

TABLE 4-2. SUMMARY OF COMBUSTION PROCESS MODIFICATION CONCEPTS

Combustion Conditions	Control Concept	Effect on Thermal NO_x	Effect on Fuel NO_x	Primary Applicable Controls		
				Operational Adjustments	Hardware Modification	Major Redesign
Decrease primary flame zone O_2 level	Decrease overall O_2 level	Reduces O rich, high NO pockets in the flame	Reduces exposure of fuel nitrogen intermediaries to O_2	Low excess air firing	Flue gas recirculation (FGR)	
	Delayed mixing of fuel and air	Flame cooling and dilution during delayed mixing reduces peak temperature	Volatile fuel N reduces to N_2 in the absence of oxygen	Burner adjustments	Low NO_x burners	Optimum burner/firebox design
	Primary fuel-rich flame zone	Flame cooling in low O , low temperature primary zone reduces peak temperature	Volatile fuel N reduces to N_2 in the absence of oxygen	Burners out of service; biased burner firing	Overfire air ports	Burner/firebox design for two stage combustion
Decrease peak flame temperature	Decrease adiabatic flame temperature	Direct suppression of thermal NO_x mechanism	Ineffective	Reduced air preheat	Water injection, FGR	
	Decrease combustion intensity	Increased flame zone cooling yields lower peak temperature	Minor direct effect; indirect effect on mixing	Load reduction		Enlarged firebox, increased burner spacing
	Increased flame zone cooling/reduce residence time	Increased flame zone cooling yields lower peak temperature	Ineffective	Burner tilt		Redesign heat transfer surfaces, firebox aerodynamics
Chemically reduce NO_x in post flame region	Inject reducing agent	Decomposition	Decomposition		Ammonia injection possible on some units	Redesign convective section for NH_3 injection

TABLE 4-3. AVERAGE NO_x REDUCTION WITH LOW EXCESS AIR FIRING (LEA)

Equipment Type	Fuel	Number of Boilers Tested	Baseline		Low Excess Air (LEA)		Average NO_x Reduction (percent)	Maximum NO_x Reduction Reported (percent)
			Stoichiometry to Active Burners (percent)	NO_x Emissions (ppm dry @ 3% O_2)	Stoichiometry to Active Burners (percent)	NO Emissions (ppm dry @ 3% O_2)		
Tangential	Coal	11	124	459	116	373	19	42
	Oil	--	--	--	--	--	--	--
	Nat Gas	1	117	340	113	245	28	28
Opposed Wall	Coal	5	126	746	118	660	12	23
	Oil	4	120	357	113	290	19	30
	Nat Gas	6	115	717	110	600	16	33
Single Wall	Coal	7 (2)	123 (134)[b]	624 (1338)	114 (118)	522 (1325)	16 (1)	25 (3)
	Oil	4	120	409	112	315	23	26
	Nat Gas	3 (1)	117 (124)	418 (992)	108 (112)	356 (931)	15 (6)	15 (6)
All Boilers	Coal	23	124	609	116	522	16	30
	Oil	8	120	383	115	302	21	28
	Nat Gas	10	116	492	110	400	20	25
	All Fuels	41	120	495	114	408	19	28

[a] Boiler load at or above 80 percent MCR. For individual tests, corresponding baseline and controlled loads were nearly identical.

[b] Numbers in parentheses refer to boilers originally designed for coal firing with wet bottom furnaces.

TABLE 4-4. AVERAGE NO_x REDUCTION WITH BURNER OUT OF SERVICE (BOOS)[a]

Equipment Type	Fuel	Number of Boilers Tested	Baseline			Burners Out of Service (BOOS)			Average NO_x Reduction (percent)	Maximum NO_x Reduction Reported (percent)
			No. of Burners Firing	Stoichiometry to Active Burners (percent)	NO_x Emissions (ppm dry @ 3% O_2)	Percent Burners on Air Only	Stoichiometry to Active Burners (percent)	NO_x Emissions (ppm dry @ 3% O_2)		
Tangential	Coal	7	32 (16-56)[b]	121	462	17	98	293	37	56
	Oil	--	--	--	--	--	--	--	--	--
	Nat Gas	1	8	112	146	NA	86	146	0	0
Opposed Wall	Coal	4	40 (24-54)[b]	122	670	16	102	522	22	46
	Oil	1	24	107	442	33	73	292	34	34
	Nat Gas	4	26[b] (16-36)[b]	115	674	28	84	290	57	61
Single Wall	Coal	8 (1)	16 (24)[c]	123 (134)[c]	618 (1196)[c]	19 (33)[c]	97 (89)[c]	412 (577)[c]	33 (52)[c]	48 (52)[c]
	Oil	3	16 (12-24)[b]	119	425	18	95	256	40	48
	Nat Gas	3	16 (12-16)[b]	117	418	22	89	214	49	69
All Boilers	Coal	19	28 (16-56)[b]	122	583	17	99	409	31	50
	Oil	4	20 (12-24)[b]	113	433	25	84	274	37	41
	Nat Gas	8	16 (8-36)[b]	115	412	25	86	217	35	43
	All Fuels	31	20 (8-56)[b]	117	476	22	90	300	34	45

[a] Boiler load at or above 80 percent MCR. For individual tests, corresponding baseline and controlled loads were nearly identical.

[b] Range in number of burners firing

[c] Numbers in parentheses refer to boilers originally designed for coal firing with wet bottom furnaces.

TABLE 4-5. AVERAGE NO_x REDUCTION WITH OVERFIRE AIR (OFA)[a]

Equipment Type	Fuel	Number of Boilers Tested	Baseline		Overfire Air (OFA)			Average NO_x Reduction (percent)	Maximum NO_x Reduction Reported (percent)
			Stoichiometry to Active Burners (percent)	NO_x Emissions (ppm dry @ 3% O_2)	Stoichiometry to Active Burners (percent)	Furnace Stoichiometry (percent)	NO_x Emissions (ppm dry @ 3% O_2)		
Tangential	Coal	6	129	454	105	122	311	31	41
	Oil	--	--	--	--	--	--	--	--
	Nat Gas	--	--	--	--	--	--	--	--
Opposed Wall	Coal	--	--	--	--	--	--	--	--
	Oil	5	118	376	96	118	287	24	30
	Nat Gas	2	114	928	99	112	378	59	66
Single Wall	Coal	--	--	--	--	--	--	--	--
	Oil	--	--	--	--	--	--	--	--
	Nat Gas	--	--	--	--	--	--	--	--

[a] Boiler load at or above 80 percent MCR. For individual tests, corresponding baseline and controlled loads were nearly identical.

TABLE 4-6. AVERAGE NO_x REDUCTION WITH FLUE GAS RECIRCULATION (FGR)[a]

Equipment Type	Fuel	Number of Boilers Tested	Baseline		Overfire Air (OFA)			Average NO_x Reduction (percent)	Maximum NO_x Reduction Reported (percent)
			Stoichiometry to Active Burners (percent)	NO_x Emissions (ppm dry @ 3% O_2)	Stoichiometry to Active Burners (percent)	FGR (percent)	NO_x Emissions (ppm dry @ 3% O_2)		
Tangential	Coal	--	--	--	--	--	--	--	--
	Oil	--	--	--	--	--	--	--	--
	Nat Gas	1	117	340	115	23	135	60	60
Opposed Wall	Coal	1	128	855	127	15	735	17	17
	Oil	1	122	304	126	11	263	13	13
	Nat Gas	--	--	--	--	--	--	--	--
Single Wall	Coal	--	--	--	--	--	--	--	--
	Oil	--	--	--	--	--	--	--	--
	Nat Gas	1	106	470	107	11	307	35	35

[a] Boiler load at or above 80 percent MCR. For individual tests, corresponding baseline and controlled loads were nearly identical.

TABLE 4-7. AVERAGE NO_x REDUCTION WITH REDUCED FIRING RATE

Equipment Type	Fuel	Number of Boilers Tested	Baseline (80% MCR or Above)			Reduced Load			Average NO_x Reduction (percent)	Maximum NO_x Reduction Reported (percent)
			Firing Rate (percent MCR)	Stoichiometry to Active Burners (percent)	NO_x Emissions (ppm dry @ 3% O_2)	Firing Rate (percent MCR)	Stoichiometry to Active Burners (percent)	NO_x Emissions (ppm dry @ 3% O_2)		
Tangential	Coal	7	93	112	462	64	127	408	12	25
	Oil	--	--	--	--	--	--	--	--	--
	Nat Gas	1	100	117	340	75	135	332	2	32
Opposed Wall	Coal	4	93	131	825	70	136	758	8	18
	Oil	4	98	118	362	61	121	249	31	48
	Nat Gas	5	98	115	651	57	115	269	59	64
Single Wall	Coal	2 (2)	92 (90)	125 (133)[a]	651 (1338)	67 (54)	130 (138)	496 (990)	24 (26)	25 (33)
	Oil	3	98	119	425	53	119	296	30	45
	Nat Gas	2 (1)	97 (98)	118 (115)	442 (992)	35 (59)	117 (131)	125 (522)	72 (47)	82 (47)
All Boilers	Coal	13	93	126	646	67	131	554	14	23
	Oil	7	98	119	393	57	120	272	31	47
	Nat Gas	8	99	117	478	55	122	242	44	59
	All Fuels	28	97	120	506	60	124	356	30	43

[a] Numbers in parentheses refer to boilers originally designed for coal firing with wet bottom furnaces.

TABLE 4-8. AVERAGE NO_x REDUCTION WITH OFF STOICHIOMETRIC COMBUSTION AND FLUE GAS RECIRCULATION (OSC AND FGR)[a]

Equipment Type	Fuel	Number of Boilers Tested	Baseline		OSC and FGR				Average NO_x Reduction (percent)	Maximum NO_x Reduction Reported (percent)
			Stoichiometry to Active Burners (percent)	NO_x Emissions (ppm dry @ 3% O_2)	Type of OSC	Stoichiometry to Active Burners (percent)	FGR (percent)	NO_x Emissions (ppm dry @ 3% O_2)		
Tangential	Coal	--	--	--	--	--	--	--	--	--
	Oil	--	--	--	--	--	--	--	--	--
	Nat Gas	1	117	340	BOOS	75	21	105	69	69
Opposed Wall	Coal	1	128	781	BOOS	99	19	453	42	42
	Oil	1	122	304	OFA	97	11	247	19	19
	Nat Gas	--	--	--	--	--	--	--	--	--
Single Wall	Coal	--	--	--	--	--	--	--	--	--
	Oil	2	118	355	BBF BOOS	91	14	154	57	59
	Nat Gas	1	106	470	BOOS	75	12	115	76	76

[a] Boiler load at or above 80 percent MCR. For individual tests, corresponding baseline and controlled loads were nearly identical.

TABLE 4-9. AVERAGE NO_x REDUCTION WITH REDUCED FIRING RATE AND OFF STOICHIOMETRIC COMBUSTION

Equipment Type	Fuel	Number of Boilers Tested	Baseline			Low Load and OSC				Average NO_x Reduction (percent)	Maximum NO_x Reduction Reported (percent)
			Firing Rate (percent MCR)	Stoichiometry to Active Burners (percent)	NO_x Emissions (ppm dry @ 3% O_2)	Firing Rate (percent MCR)	Type of OSC	Stoichiometry to Active Burners (percent)	NO_x Emissions (ppm dry @ 3% O_2)		
Tangential	Coal	8	93	122	453	61	BOOS OFA	95	248	45	62
	Oil	--	--	--	--	--	--	--	--	--	--
	Nat Gas	--	--	--	--	--	--	--	--	--	--
Horizontally Opposed Wall	Coal	3	93	129	820	73	BOOS	102	634	23	32
	Oil	4	99	118	362	64	BOOS OFA	117	177	51	67
	Nat Gas	6	100	115	717	58	BOOS OFA	88	148	79	89
Single Wall	Coal	4 (2)	90	124 (133)[a]	663 (1338)	73 (59)	BOOS	99 (91)	381 (887)	43 (34)	50 (55)
	Oil	3	98	120	426	56	BBF BOOS	97	228	46	59
	Nat Gas	2 (1)	97 (98)	118 (125)	442 (992)	35 (71)	BBF BOOS	93 (102)	78 (641)	82 (35)	87 (35)
All Boilers	Coal	15	92	125	645	69	BOOS OFA	99	421	37	48
	Oil	7	99	119	394	60	BBF BOOS OFA	107	202	49	63
	Nat Gas	8	99	117	579	31	BOOS OFA	91	113	80	88
Fuels	All	30	97	120	539	53	BBF BOOS OFA	99	245	55	66

[a] Numbers in parentheses refer to boilers originally designed for coal firing with wet bottom furnaces.

TABLE 4-10. AVERAGE NO_x REDUCTION WITH LOAD REDUCTION, OFF STOICHIOMETRIC COMBUSTION AND FLUE GAS RECIRCULATION

Equipment Type	Fuel	Number of Boilers Tested	Baseline			Controlled/Low Load and OSC and FGR				NO_x Emissions (ppm dry @ 3% O_2)	Average NO_x Reduction (percent)	Maximum NO_x Reduction Reported (percent)
			Firing Rate (percent MCR)	Stoichiometry to Active Burners (percent)	NO_x Emissions (ppm dry @ 3% O_2)	Firing Rate (percent MCR)	Type of OSC	Stoichiometry to Active Burners (percent)	FGR (percent)			
Tangential	Coal	--	--	--	--	--	--	--	--	--	--	--
	Oil	--	--	--	--	--	--	--	--	--	--	--
	Nat Gas	--	--	--	--	--	--	--	--	--	--	--
Opposed Wall	Coal	--	--	--	--	--	--	--	--	--	--	--
	Oil	3	99	118	398	46	BOOS OFA	87	39	194	56	59
	Nat Gas	2	100	113	945	43	BOOS OFA	90	27	130	87	90
Single Wall	Coal	--	--	--	--	--	--	--	--	--	--	--
	Oil	2	98	118	355	62	BOOS	92	30	152	57	57
	Nat Gas	2	100	110	421	65	BOOS	81	20	171	59	83
All Boilers	Coal	--	--	--	--	--	--	--	--	--	--	--
	Oil	5	99	118	376	54	BOOS OFA	90	35	173	57	58
	Nat Gas	4	100	112	683	54	BOOS OFA	86	23	150	73	87
	All Fuels	9	100	115	530	54	BOOS OFA	88	29	162	66	73

The average NO_x reductions reported in Tables 4-3 through 4-10 were calculated in the following manner. First, reductions obtained from all tests on each particular boiler were arithmetically averaged. Only tests with the same NO_x control technique were used. Next, these average NO_x reductions were again arithmetically averaged using all the boilers within the same firing type/fuel classification. All other numerical table entries, such as burner stoichiometry, firing rate, etc., were calculated in a similar manner.

It should be noted that baseline emission data vary occasionally between tables for the same firing type/fuel classification. The reason for this variation is that only the baseline tests and the corresponding controlled tests with the particular control technique under consideration were used in the averaging procedure described above. For example, if NO_x emissions from boiler "A" firing coal were controlled only with the technique of low excess air, then the baseline data from that boiler would be used only to calculate the average emissions reported in Table 4-3, and not used in deriving average baseline emissions in Tables 4-4 through 4-10, for other techniques. NO_x reductions reported in these tables represent values typical of what can be expected when control techniques are implemented. Descriptions of these control techniques follow.

4.2.1 Low Excess Air (LEA)

Reducing the excess air level in the furnace has generally been found to be an effective method of NO_x control. In this technique, the combustion air is reduced to the minimum amount required for complete combustion, maintaining acceptable furnace cleanliness and steam temperature. With less oxygen available in the flame zone, both thermal and fuel NO_x formation are reduced (Reference 4-22). In addition, the reduced airflow lowers the quantity of flue gas released resulting in an improvement in boiler efficiency.

Low excess air firing is usually the first NO_x control technique applied. It may be used with virtually all fuels and firing methods. However, furnace slagging and tube wastage considerations may limit the degree of application (Reference 4-22). Low excess air may also be employed in combination with the other NO_x control methods (Reference 4-33).

Many units use excess air for control of steam temperature, especially at lower loads, often as an alternative to flue gas recirculation. Reducing the excess air levels on these units would tend to lower the outlet steam temperature and thus reduce cycle efficiency unless the improvement in boiler efficiency is enough to compensate for the lower steam temperature (Reference 4-34).

In low excess air firing, there is often a greater burden on operating personnel. The attempt to optimize the excess air level requires close monitoring of flue gas O_2 and CO analyzers. In coal firing, the operator must also check the furnace periodically for excessive slag deposits. Accurate flue gas analyzers will often need to be purchased if not already installed.

As shown in Table 4-3, Average NO_x Reduction with Low Excess Air Firing, low excess air firing results in an average NO_x reduction of 16 percent for coal, 21 percent for oil, and 20 percent for natural gas firing.

4.2.2 Off Stoichiometric Combustion (OSC)

Off stoichiometric, or staged combustion seeks to control NO_x by carrying out initial combustion in a primary, fuel-rich, combustion zone, then completing combustion, at lower temperatures, in a second, fuel lean zone. In practice, OSC is implemented through biased burner firing (BBF), burners out of service (BOOS), or overfire air injection (OFA).

4.2.2.1 Biased Burner Firing (BBF), Burners Out of Service (BOOS)

Biased burner firing consists of firing the lower rows of burners more fuel rich than the upper rows of burners. This may be accomplished by maintaining normal air distribution to the burners while adjusting fuel flow so that a greater amount of fuel enters the furnace through the lower rows of burners than through the upper rows of burners. Additional air required for complete combustion enters through the upper rows of burners which are firing air rich.

In the burners out of service mode, individual burners, or rows of burners, admit air only. This reduces the airflow through the fuel admitting or active burners. Thus the burners are firing more fuel rich than normal, with the remaining air required for combustion being admitted through the inactive burners.

These methods reduce NO_x emissions by reducing the excess air available in the firing zone. This reduces fuel and thermal NO_x formation. These techniques are applicable to all fuels and are particularly attractive as control methods for existing units since few, if any, equipment modfications are required (References 4-33 and 4-35). In some cases, however, derating of the unit may be required if there is too limited extra firing capability with the active burners. This is most likely to be a problem with pulverized coal units without spare pulverizer capacity.

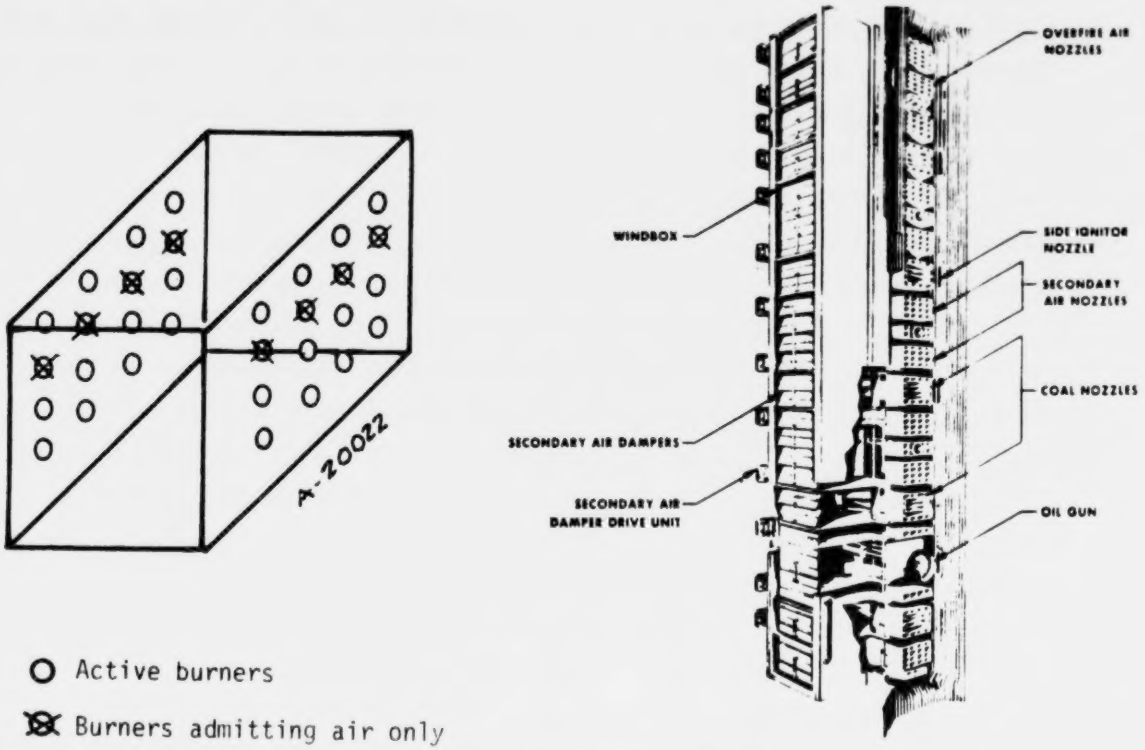
Monitoring flue gas composition, especially O_2 and CO concentrations, is very important when employing these combustion modifications for NO_x control. Local reducing atmospheres may cause increased tube wastage when firing coal and high sulfur oils. They may also cause increased furnace slagging when burning coal because of the lower ash fusion temperature associated with reducing atmospheres (References 4-34 and 4-36). In addition, it is important to closely monitor flue gas, excess air, and CO to avoid reducing boiler efficiency through flue gas heat and unburned combustible losses, and to prevent unsafe operating conditions caused by incomplete combustion. For these reasons, accurate flue gas monitoring equipment and increased operator monitoring of furnace conditions are required with these combustion modifications.

As shown in Table 4-4, burners out of service firing results in an average NO_x reduction of 31 percent for coal, 37 percent for oil, and 35 percent for natural gas firing. A typical burners out of service pattern is shown in Figure 4-5(a).

4.2.2.2 Overfire Air (OFA)

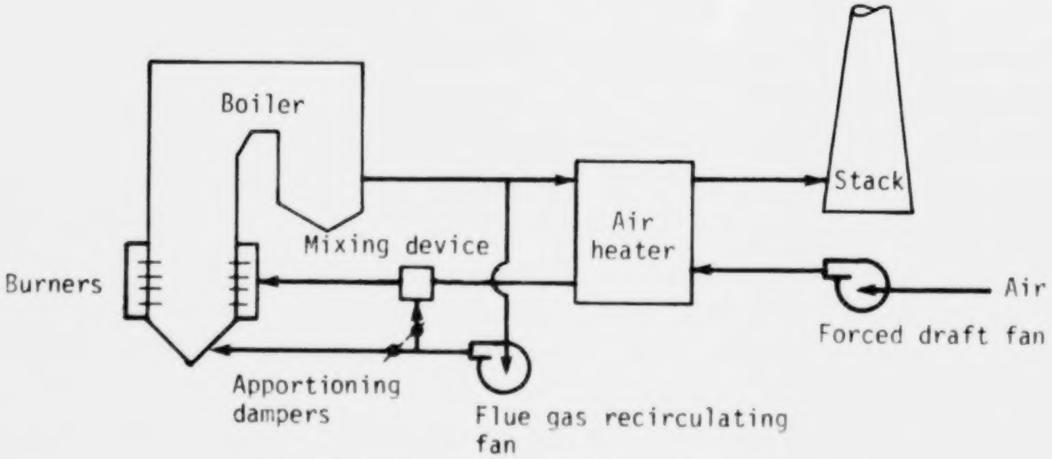
The overfire air technique for NO_x control involves firing the burners more fuel rich than normal while admitting the remaining combustion air through overfire air ports or an idle top row of burners.

Overfire air is very effective for NO_x reduction and may be used with all fuels. However, there is an increased potential for furnace tube wastage due to local reducing conditions when firing coal or high sulfur oil. There is also a greater tendency for slag accumulation in the furnace when firing coal (References 4-22, 4-35 through 4-37). In addition, with reduced airflow to the burners, there may be reduced mixing of the fuel and


A-20022
O Active burners
⊗ Burners admitting air only
OVERFIRE AIR NOZZLES
WINDBOX
SIDE IGNITOR NOZZLE
SECONDARY AIR NOZZLES
COAL NOZZLES
SECONDARY AIR DAMPERS
SECONDARY AIR DAMPER DRIVE UNIT
OIL GUN

a. Typical burners out of service arrangement opposed fired unit

b. Typical overfire air system for tangential fired unit (Reference 4-21)


Boiler
Stack
Air heater
Mixing device
Burners
Air
Forced draft fan
Apportioning dampers
Flue gas recirculating fan

c. Typical flue gas recirculation system for NO_x control

Figure 4-5. Typical arrangements for (b) overfire air, (a) burners out of service, and (c) flue gas recirculation.

air. Thus, additional excess air may be required to ensure complete combustion. This may result in a decrease in efficiency (References 4-35 and 4-37).

Overfire air is more attractive in original designs than in retrofit applications for cost considerations. Additional duct work, furnace penetrations, and extra fan capacity may be required. There may be physical obstructions outside of the boiler setting making installation more costly. Or, there may also be insufficient height between the top row of burners and the furnace exit to permit the installation of overfireair ports and the enlarged combustion zone created by the staged combustion technique (Reference 4-35).

As shown in Table 4-5, the limited data indicate that with overfire air, NO_x reductions of about 31 percent for coal, 24 percent for oil, and 59 percent for natural gas are possible. A typical overfire air system is shown in Figure 4-5(b).

4.2.3 Low NO_x Burners (LNB)

Several utility boiler manufacturers have been active in the development of new burners designed to reduce NO_x emissions from coal-fired units. Although the techniques of low excess air and off stoichiometric (staged) combustion have been shown to be effective in reducing NO_x levels, there has been some concern as to potential increased slagging and corrosion with OSC operation. Furnaces fired with certain Eastern U.S. bituminous coals with high sulfur contents may be especially susceptible to corrosion attack under reducing atompsheres. Local reducing atmosphere pockets may exist under off stoichiometric operation. The problem may be further aggravated by slagging since slag generally fuses at lower temperatures under reducing conditions. The sulfur in the molten slag may then readily attack the tube walls. Faced with these potential problems and stricter NO_x NSPS, manufacturers are developing and marketing low NO_x burners which permit staging at the burners themselves, away from the water wells, thus minimizing the potential corrosion and slagging problems associated with OSC operation.

Most low NO_x burners designed for utility boilers control NO_x by reducing flame turbulence, delaying fuel/air mixing, and establishing fuel-rich zones where combustion initially takes place. This represents a departure from the usual burner design procedures which promote high turbulence, high intensity, rapid combustion flames. The longer, less intense flames produced with low NO_x burners result in lower flame temperatures which reduce thermal NO_x generation. Moreover, the reduced availability of oxygen in the initial combustion zone inhibits fuel NO_x conversion. Thus, both thermal and fuel NO_x are controlled by the low NO_x burners.

The Babcock and Wilcox Company is currently installing the Dual Register Pulverized Coal-Fired Burner in all its new utility boilers in order to meet current NSPS (References 4-38 and 4-39). The limited turbulence, controlled diffusion flame burner is designed to minimize fuel and air mixing at the burner to that required to obtain ignition and sustain stable combustion of the coal. A Venturi mixing device, located in the coal nozzle, provides a uniform coal/primary air mixture at the burner. Secondary air is introduced through two concentric zones surrounding the coal nozzle, each of which is independently controlled by inner and outer air zone registers. Adjustable spin vanes are located in the inner air zone to provide varying degrees of swirl to the inner air to control coal/air mixing during the combustion process. In addition, the windbox is compartmented to provide airflow control on a per pulverizer basis, thus permitting operation with lower excess air while maintaining an oxidizing atmosphere around each burner.

To date seven dual register burner-equipped utility boilers have been tested for NO_x emissions (Reference 4-39). For the four bituminous coal-fired units tested, NO_x emissions ranged from 194 to 258 ng/J (0.45 to 0.6 $lb/10^6$ Btu, 318 to 422 ppm) at or below the current 258 ng/J (0.6 $lb/10^6$ Btu) NSPS for bituminous coal. The three subbituminous coal-fired units exhibited NO_x emissions in the range of 129 to 151 ng/J (0.3 to 0.35 $lb/10^6$ Btu, 211 to 247 ppm), well below the current 215 ng/J (0.5 $lb/10^6$ Btu) NSPS for subbituminous coal. It should be noted that these low NO_x burner-equipped boilers came onstream when the original 1971 NSPS of 301 ng/J (0.7 $lb/10^6$ Btu) was still in effect.

Comparisons with NO_x emissions from similar units equipped with the high turbulence older burners show reductions in NO_x levels from 40 to 60 percent due to the new burner design. As explained above, the majority of the reduction is attributable to controlled air-coal mixing in the furnace chamber. The resulting lower peak flame temperature and the decreased availability of oxygen in the primary flame zone tend to suppress thermal NO_x generation and fuel nitrogen conversion.

B&W claims that NO_x control through its Dual Register Burners is superior to staging as it maintains the furnace in an oxidizing environment, hence minimizing slagging and reducing the potential for furnace wall corrosion when firing high sulfur bituminous coal. Also, more complete carbon utilization can be achieved due to better coal-air mixing in the furnace. Finally, lower oxygen levels are required with all the combustion air admitted through the burners rather than having some of the total air injected above the burner zone.

Although the Dual Register Burners were developed for use in new boilers, they can also be retrofitted to older units. However, the new boilers are also designed to provide airflow control on a per pulverizer basis. This may not be possible in some of the older units, or the cost involved in retrofitting a compartmented windbox and making the necessary changes in pulverizer burner piping may be prohibitive. If careful control of fuel and air to each burner is not feasible, the burners will not be as effective in reducing NO_x emissions. Nevertheless, the new burners should reduce NO_x levels below those obtained with the older high turbulence burners. They may still be considered for retrofit application, perhaps in conjunction with other NO_x control techniques, but much development work remains.

Foster Wheeler Energy Corporation has developed a dual register coal burner for installation in its new boilers (References 4-36 and 4-40). The new burner reduces turbulence as compared to the older designs and causes controlled, gradual mixing of fuel and air at the burner. This is achieved using a dual throat with two registers which splits the secondary air into two concentric streams with independently variable swirl. The mixing rate between the primary and secondary air streams and the rate of entrainment of furnace gases can thus be varied. The primary air velocity can also be varied by the use of a coal nozzle in the shape of a tapered annulus with an axially movable inner sleeve tip. In addition, a perforated plate air hood surrounds the burner and is used to measure airflow, improve burner circumferential air distribution, and provide a discrete means for balancing air on a burner to burner basis.

New Foster Wheeler utility boilers are equipped with OFA ports in addition to the new low NO_x burners. The OFA ports are installed for use in cases where the new burners alone cannot reduce NO_x levels to meet the NSPS requirements. However, even when staging has to be employed, it is expected that in most cases the total burner fuel/air ratios will be above stoichiometric, as part of the NO_x reduction burden is assumed by the burners. Reducing atmospheres are therefore avoided for the most part, thus minimizing associated slagging and corrosion problems. The new burners with cooler, less intense flames, and the larger new furnace designs with lower burner zone heat liberation rates also tend to reduce slagging while at the same time decrease thermal NO_x formation.

Test results for the new Foster Wheeler burners are reported in References 4-36 and 4-40. Reductions in NO_x emissions of about 40 percent were observed on a four-burner steam generator when operated at full load with the new burners. Three utility steam generators, two 265 MW opposed fired units and one 75 MW front wall fired unit, have been retrofitted with the new burners and tested for NO_x emissions. Controlled NO_x emissions were in the 172 ng/J (0.4 lb/10^6 Btu, 281 ppm) to 215 ng/J (0.5 lb/10^6 Btu, 352 ppm range. Test results on one of the 265 MW units are reported and show a 48 percent drop in NO_x emissions due to the new burners. When the boiler was operated with the new burners and overfire air in conjunction, reductions in NO_x levels of 67 percent were achieved with the OFA ports 100 percent open. Under such conditions, however, slag began to accumulate after about 24 hours of continuous full load operation and unburned carbon in the flyash increased to 2.4 percent. Under normal operating procedure, with OFA ports not more than 20 percent open, the NO_x reduction was approximately 40 to 50 percent over the uncontrolled case. Carbon monoxide was maintained below 50 ppm and unburned carbon in the flyash was less than 1 percent.

The general results and trends were found to be similar for the other two units tested. The uncontrolled NO_x levels of all these units were in the range of 367 to 397 ng/J (600 to 650 ppm). This is atypically low for older units equipped with high turbulence burners. Installation of new burners and adjusting them for low NO_x operation combined with OFA operation with ports open up to 20 percent reduced NO_x levels down to 183 to 214 ng/J (300 to 350 ppm). This represents normal low NO_x operating procedure for these units. When OFA ports are opened 100 percent and the burners are adjusted for minimum NO_x emissions, NO_x levels of 122 to 137 ng/J (200 to 225 ppm) were attained. Slagging, however, resulted under these operating conditions. In all cases a good quality low sulfur coal was used so that tube wastage problems did not occur. Since the test units were not designed for staged combustion, the slagging effect was expected. However, slagging when overfire air ports were open was significantly less with the low NO_x burners than with the original high turbulence burners.

Although experience with the new burners, alone and in combination with staging, has been successful it has been limited to a few boilers and a particular type of coal. Minimum NO_x levels obtained with these fuels may not be repeated with a higher nitrogen content, lower heating value coal.

In addition to NO_x control in new units, the Foster Wheeler dual register burner is well suited (technically) for retrofit application. The airflow to the new burners is controlled individually at each burner by means of the perforated hood. Hence, precise air/fuel control at each burner is possible without incurring major hardware changes besides burner replacement.

In the tests referred to above, NO_x levels were approximately halved by the use of the new retrofitted burners alone. The burners can also be used with oil. In fact the original patent for the dual register burner was designed for and tested with oil. No detailed data on oil-fired utility boilers fitted with the new burners have been released to date. However, Babcock & Wilcox has reported the successful retrofit of an oil-fired dual register burner, reducing NO_x emissions to below 129 ng/J (0.3 lb/10^6 Btu, 225 ppm) (Reference 4-39).

Riley Stoker Corporation is currently modifying the burners used in its turbo furnace to lower NO_x emissions (Reference 4-41). The new burners are designed to be more flexible and to control fuel/air mixing to reduce thermal and fuel NO_x. With the new burners and changes in furnace design Riley Stoker expects to meet current NSPS requirements without increased carbon or unburned hydrocarbon losses. The new burners can be used with coal, oil, and gas fuels but are not being considered for retrofit application. No test data are available on the performance of the new burners at present.

In summary, low NO_x burners appear very attractive, with potential NO_x reductions of the order of 50 percent. Data from long term, full scale demonstrations are imminent, and commercial application is well underway. Indeed, LNB appears to be the preferred combustion modification technique for coal-fired utility boilers.

4.2.4 Flue Gas Recirculation (FGR)

Flue gas recirculation for NO_x control consists of extracting a portion of the flue gas from the economizer outlet and returning it to the furnace, admitting the flue gas through the furnace hopper or through the burner windbox or both. Flue gas recirculation lowers the bulk furnace gas temperature and reduces oxygen concentration in the combustion zone (References 4-35 and 4-37).

Flue gas recirculation through the furnace hopper and near the furnace exit has long been used for steam temperature control. Flue gas recirculation through the windbox and, to a lesser degree, through the furnace hopper is very effective for NO_x control on gas- and oil-fired units (References 4-33 and 4-37). However, it has been shown to be relatively ineffective on coal fired units (Reference 4-19).

Flue gas recirculation for NO_x control is more attractive for new designs than as a retrofit application. Retrofit installation of flue gas recirculation can be quite costly. The fan, flues, dampers, and controls as well as possibly having to increase existing fan capacity due to increased draft loss, can represent a large investment. In addition, the flue gas recirculation system itself will require a substantial maintenance program due to the high temperature environment experienced and potential erosion from entrained ash. Thus the cost-effectiveness of this method of NO_x control has to be examined carefully when comparing it to other control techniques.

As a new design feature, the furnace and convective surfaces can be sized for the increase in mass flow and change the furnace temperatures. In contrast in retrofit applications, the increased mass flow increases turbulence and mixing in the burner zone, and alters the convective section heat absorption. Erosion and vibration problems may result (References 4-37 and 4-38). Flame detection can also be difficult with flue gas recirculation through the windbox. In addition, controls must be employed to regulate the proportion of flue gas to air so that sufficient concentration of oxygen is available for combustion (Reference 4-43).

As shown in Table 4-6, the limited data indicate that with flue gas recirculation alone, average NO_x reductions of about 17 percent for coal, 13 percent for oil, and 47 percent for gas have been achieved. It should be noted that these values are based on very limited data comparing the effects of flue gas recirculation alone to baseline conditions. (Additional data are discussed in Section 6.) Data comparing the effects of flue gas recirculation in combination with other control methods to baseline conditions are more plentiful and briefly discussed below. A typical flue gas recirculation system is shown in Figure 4-5(c).

4.2.5 Reduced Firing Rate

Thermal NO_x formation generally increases as the volumetric heat release rate or combustion intensity increases. Thus, NO_x can be controlled by reducing combustion intensity through load reduction, or derating, in existing units and by enlarging the firebox in new units. The reduced heat release rate lowers the bulk gas temperature which in turn reduces thermal NO_x formation (Reference 4-44).

The heat release rate per unit volume is generally independent of unit rated power output. However, the ratio of primary flame zone heat release to heat removal increases as the unit capacity is increased. This causes NO_x emissions for large units to be generally greater than for small units of similar design, firing characteristics, and fuel.

The increase in NO_x emissions with increased capacity is especially evident for gas-fired boilers, since total NO_x emissions are due to thermal NO_x. However, for coal-fired and oil-fired units the effects of increased capacity are less noticeable, since the conversion of fuel nitrogen to NO_x for these fuels represent a major component of total NO_x formation. Still, a reduction in firing rate will affect firebox aerodynamics which may, consequently, affect fuel NO_x emissions. But such effects on fuel NO_x production are less significant.

Table 4-7 presents a compilation of available data on NO_x reduction as a result of reduced firing rate. For coal firing, an average of 15 percent reduction in NO_x resulted from a 28 percent reduction in firing rate. For oil firing, an average of 30 percent reduction in NO_x resulted from a 42 percent reduction in firing rate. For gas firing, an average of

44 percent reduction in NO_x resulted from a 44 percent reduction in firing rate. Thus, reduction of NO_x with lowered firing rate is most evident with gas-fired boilers.

Reduced firing rate often leads to several operating problems. Aside from the limiting of capacity, low load operation usually requires higher levels of excess air to maintain steam temperature and to control smoke and CO emissions. The steam temperature control range is also reduced substantially. This will reduce the operating flexibility of the unit and its response to changes in load. The combined results are reduced operating efficiency due to higher excess air and reduced load following capability due to a reduction in control range.

When the unit is designed for a reduced heat release rate, the problems associated with derating are largely avoided. The use of an enlarged firebox produces NO_x reductions similar to load reduction on existing units.

4.2.6 Combination of Controls

To achieve required NO_x emission levels, it is often necessary to use a combination of control methods. Low excess air operation is common to all combined control method strategies. Other control combinations that are most effective are primarily fuel dependent. It is important in this respect to distinguish retrofit controls from original design controls. Unfortunately the test data available are primarily from retrofit control applications.

Tables 4-8 through 4-10 represent compilations of test data from employing combinations of controls to reduce NO_x emissions. Detailed data from combined controls tests are very limited. Table 4-11 extends the data presented in previous tables and lists highest NO_x reductions attained through combinations of controls as a function of boiler/fuel classification. This table represents the best results achieved in specific applications and should not be interpreted as generally achievable NO_x reductions. In comparing Tables 4-3 through 4-7 to Tables 4-8 through 4-10, it is seen that in combining control techniques, results are complementary but not additive for NO_x reduction.

4.3 ADVANCED CONTROLS

Several other combustion NO_x control techniques, which show promise for future application, are in varying stages of development.

TABLE 4-11. MAXIMUM REPORTED NO_x REDUCTION ACHIEVED WITH BOILER LOAD AT OR ABOVE 80 PERCENT MCR[a]

Equipment Type	Fuel	Control Techniques Implemented	Firing Rate (percent MCR)	Stoichiometry to Active Burners (percent)	Furnace Stoichiometry (percent)	FGR (percent)	NO_x Emissions (ppm dry @ 3% O_2)	Maximum NO_x Reduction (percent)
Tangential	Coal	OFA	85	85	113	--	196	66
	Oil	Reduced Firing Rate (RFR) + BOOS + FGR	68	110	122	NA	110	55
	Nat Gas	RFR + FGR	50	110	110	32	65	81
Opposed Wall	Coal	BOOS	83	80	107	--	334	53
	Oil	BOOS + OFA	100	73	119	--	222	53
	Nat Gas	BOOS + OFA	100	69	111	--	205	79
Single Wall	Coal	BOOS	82 (81)[b]	86 (80)	115 (120)	-- --	225 (386)	63 (68)
	Oil	BOOS + FGR	96	91	121	40	145	60
	Nat Gas	BOOS (LEA)[b]	98 (100)	88 (123)	117 (123)	-- --	109 (931)	71 (6)
Average All Boilers	Coal	BOOS + OFA	83	84	112	--	252	61
	Oil	BOOS + OFA + FGR	98	82	120	20	183	56
	Nat Gas	BOOS + OFA	99	78	114	--	194	67
	All Fuels	BOOS + OFA + FGR	94	81	115	7	210	61

[a] For individual tests, corresponding baseline and controlled loads were nearly identical.

[b] Numbers in parentheses refer to boilers originally designed for coal firing with wet bottom furnaces.

advanced burner and furnace concepts, and non-catalytic homogeneous NO_x reduction with ammonia injection in the boiler's convective section.

4.3.1 Advanced Burner/Furnace Designs

A number of advanced burner designs are being developed and tested to reduce NO_x emissions from coal- and oil-fired utility and industrial boilers. Advanced burners, as compared to low NO_x burners, are defined as those devices still under experimental or pilot scale development for lowering NO_x emissions. Burner modification has the potential of lowering NO_x emissions well below levels attainable by conventional combustion modification techniques. Burner modification also has the advantage of requiring minimal changes in current boiler design and operation and is suitable for retrofit application.

TRW, Incorporated is developing an advanced burner for oil- and gas-fired commercial and industrial boilers with potential application to utility boilers. The burner uses shaped fuel injection ports to control fuel and air mixing and entrain combustion products into the flame zone (Reference 4-45). In addition to reducing thermal NO_x, the burner is effective in controlling fuel nitrogen conversion. In tests with residual oils in a packaged boiler and a large industrial size boiler, the burner was capable of reducing NO_x emissions by about 30 percent to values below 200 ppm. A preliminary timetable for the industrial burner calls for commercial application at the end of 1979 (Reference 4-46). An EPA-sponsored field demonstration is underway and actual operating data should soon be available (Reference 4-47).

Some manufacturers of oil-firing equipment are in the process of developing burners capable of operating at very low levels of excess air. The low excess air requirements increase boiler efficiency and reduce fan power consumption while decreasing NO_x emissions. The low excess air may also reduce SO_3 conversion. The Peabody Engineering Company has designed the Air Pressure Recovery (APR) burner designed to operate at excess oxygen levels down to 1/2 percent without increase in particulate and unburned hydrocarbon emissions. The Coen Company is developing the LEA burner which uses a tip swirler to operate down to 0.1 percent excess oxygen (Reference 4-48). Both burners are currently undergoing testing and no data on NO_x emissions are available.

For coal-fired utility boilers, Foster Wheeler is currently testing an advanced dual register split frame burner design. A device added at the burner nozzle splits the primary air-coal flow into several distinct streams. Coal particles become concentrated within each stream and, hence diffuse more slowly into the secondary air. This further inhibits NO_x formation by extending the slow-burning characteristics of the dual register burner. Results from an industrial size test boiler are promising with a NO_x level of approximately 129 ng/J (0.3 $lb/10^6$ Btu) for subbituminous coal (Reference 4-40). However, the burner tested on a 375 MW electrical output boiler produced approximately 215 ng/J (0.5 $lb/10^6$ Btu). A further modification of this burner with a variable velocity split flame nozzle will be installed, and a NO_x level of 151 to 172 ng/J (0.35 to 0.4 $lb/10^6$ Btu) is expected (Reference 4-49). The new design permits the velocity of the primary air-coal stream to be optimized for minimum NO_x consistent with flame stability and minimum CO.

Babcock & Wilcox and Energy and Environmental Research, under EPA sponsorship, are developing an advanced utility coal burner for low NO_x, the distributed fuel/air mixing burner, for field testing (Reference 4-50). The burner is designed to control both thermal and fuel NO_x. It is estimated that in uncontrolled pulverized coal combustion, thermal NO_x represents approximately 15 percent of the total NO_x, the volatile component of fuel NO_x contributes 65 percent, and the char component about 20 percent (Reference 4-51). In the distributed mixing burner thermal NO_x is reduced by minimizing peak flame temperature. Volatile NO_x is reduced by maintaining fuel-rich conditions in the flame zone. NO_x formation can also be reduced by increasing residence times in the rich zone, thus promoting reduction of NO_x by hydrocarbon and char fragments. For char NO_x, no effective control measures are available, but the char component can be reduced by maximizing evolution of nitrogen with the volatiles. This can be accomplished by providing for adequate residence times in the rich flame zone at high temperature.

The distributed fuel-air mixing burner design injects coal and primary air from the center of the burner with a moderate axial component. This stream is surrounded by a divided secondary airstream with a swirl component for stabilization. Tertiary air for burnout is added axially around the periphery of the burner. The arrangement results in a hot, rich recirculation zone at the center of the flame with stoichiometric ratios as high as 2 or more. Adequate time at high temperature is also provided to maximize evolution of nitrogen from the char. This time in the rich zone helps reduce most of the NO_x that may be formed. Also, axial addition of the tertiary air leads to a large flame zone. Heat extraction prior to completion of burnout along with dilution of the tertiary air by combustion products lowers the peak flame temperature, thus reducing thermal NO_x. Although experimental prototypes have achieved NO_x emissions below 86 ng/J (0.2 lb/10^6 Btu), actual field testing is not expected to be complete until late 1982 (Reference 4-50).

Babcock and Wilcox Company is developing a primary combustion furnace concept for coal-fired utility boilers in a program sponsored by the Electric Power Research Institute (Reference 4-52). The fundamental process to control NO_x in this concept is conversion of fuel nitrogen to N_2 through fuel-rich combustion. Pulverized coal is introduced into an extended combustor with substoichiometric air, so that combustion occurs under fuel-rich conditions isolated from the rest of the furnace. The length of the combustor is sufficient to provide the necessary residence time to partially oxidize the coal and permit the desirable N_2 producing reactions to occur. Heat is removed along the combustion chamber to prevent slagging. Secondary air is added at the exit of the primary combustion furnace to bring the combustion products to oxidizing conditions before they enter the furnace. Pilot scale testing of a 1 MW (4 x 10^6 Btu/hr) heat input prototype has achieved the targeted NO_x level of below 86 ng/J (0.2 lb/10^6 Btu). Commercial offering of a full scale furnace is not expected until at least 1983 (Reference 4-52).

In summary, advanced burner/furnace concepts though promising, still require several years of development. It remains to be seen whether these advanced burners may need to be combined with other combustion modification techniques as well.

4.3.2 Ammonia Injection

The use of ammonia as a potential homogeneous NO_x reducing agent was first reported by Wendt, et al. (Reference 4-53). However, these authors attributed their results to the pyrolysis of ammonia to hydrogen with the hydrogen in turn reacting with NO. The postflame decomposition of NO_x by reducing agents has more recently shown promise as a method for augmenting combustion modifications if stringent emission limits are to be met. Lyon (Reference 4-54) has reported that selective homogeneous reduction of NO in combustion effluents was possible with direct injection of ammonia within a specific temperature range.

The gas phase reaction in the temperature range of 1090K (1500°F) to 1310K (1900°F) converts nitric oxide, in the presence of oxygen and ammonia, into nitrogen and water according to the following chain reaction (Reference 4-55):

$$NH_2 + NO \qquad N_2 + H + OH \tag{4-6}$$

$$NH_2 + NO \qquad N_2 + H_2O \tag{4-7}$$

$$H + O_2 \qquad OH + O \tag{4-8}$$

$$O + NH_3 \qquad OH + NH_2 \tag{4-9}$$

$$OH + NH_3 \qquad H_2O + NH_2 \tag{4-10}$$

$$H + NH_3 \qquad H_2 + NH_2 \tag{4-11}$$

Oxygen acts as a catalyst in reducing ammonia to the intermediate NH_2 compound which in turn reacts selectively with NO, reducing it to N_2 and water. Based on this discovery a patent under the name Thermal De-NO_x was issued to Exxon Research and Engineering for this NO_x reduction technique.

Results of lab scale tests show that the level of NO_x reduction depends on the combustion product temperature, initial NO_x concentration, and quantity of ammonia injected. The data shown in Figures 4-6 through 4-8 was obtained by Muzio, et al. (Reference 4-56) during pilot-scale tests using a 59 kW (200,000 Btu/hr) heat input plug flow combustion tunnel burning natural gas. Figure 4-6 shows the effect of temperature and ammonia/nitric oxide ratio on the reduction of NO for an initial NO level of 300 ppm and an excess oxygen level of 4 percent. It dramatically illustrates the narrow temperature window for optimal NO reduction. This optimal temperature range is near 1240K (1780°F), where reductions of 30 to 90 percent were achieved with ammonia injections of 0.3 to 1.6 times the initial concentration of NO. Although increasing the ratio of ammonia to nitric oxide reduced more NO, Figure 4-7(a) shows that for NH_3/NO ratios of greater than 2, essentially no further reduction of NO was achieved. The additional ammonia injected at 1240K leaves unreacted. However, when the reaction temperature is greater than 1300K, the ammonia reacts with oxygen to form additional NO, an undesirable situation. Thus, at these higher

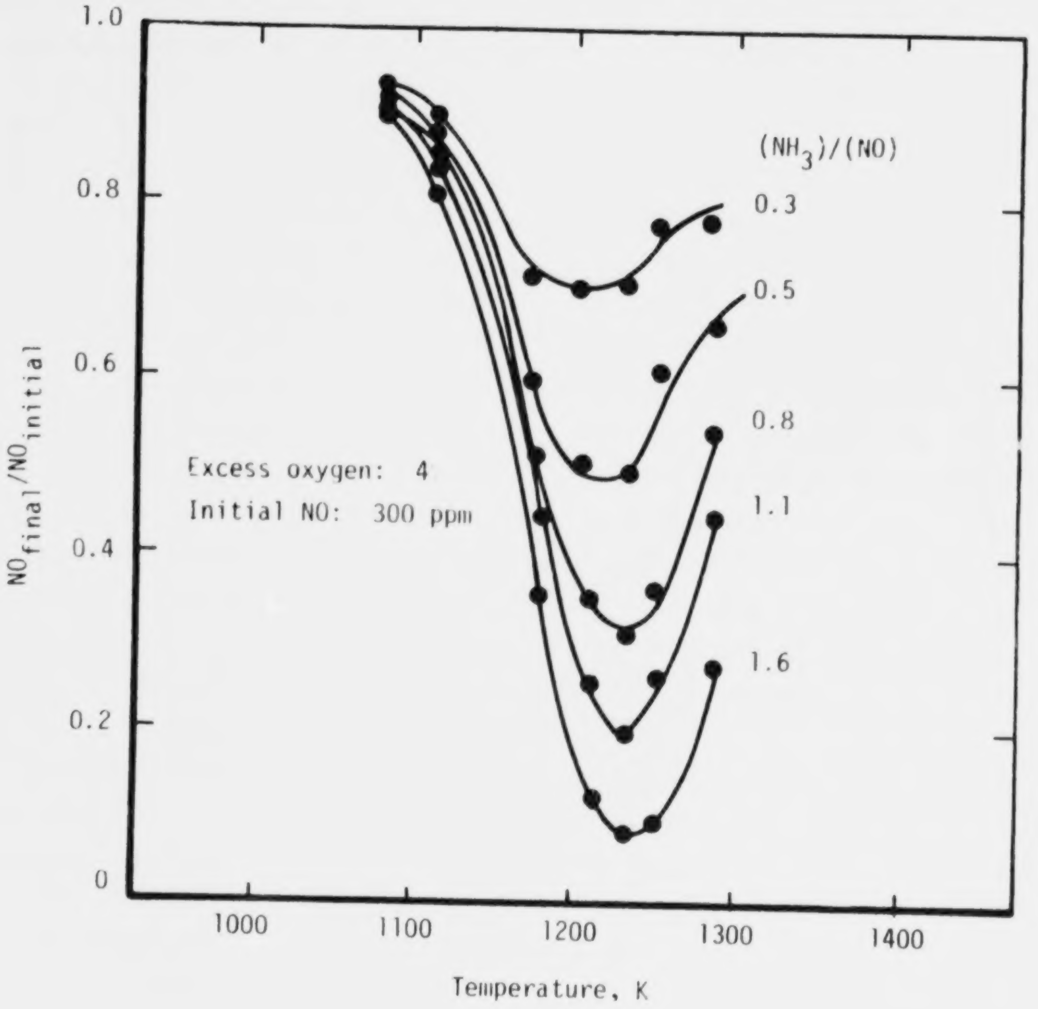
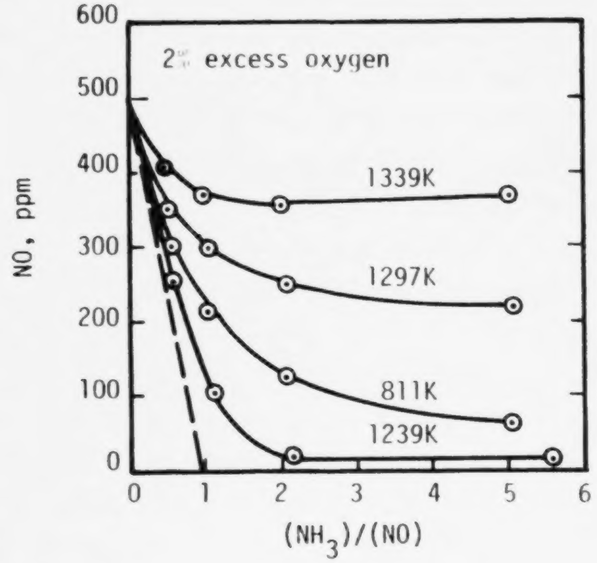
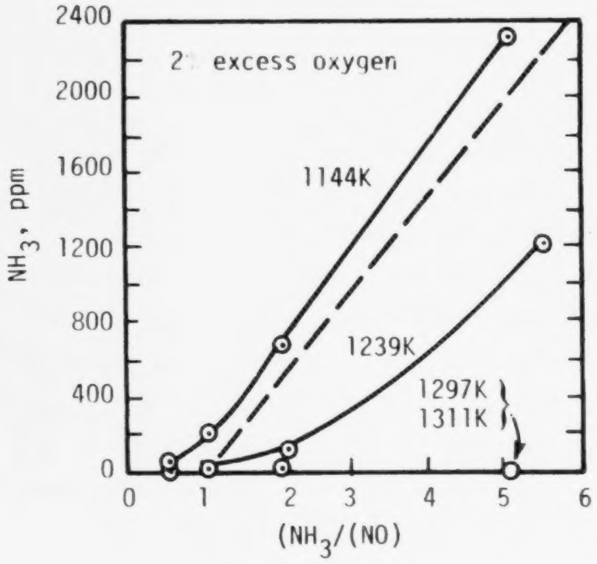


Figure 4-6. Effect of temperature on NO reduction with ammonia injection (Reference 4-56).



a. Nitric oxide reduction



b. Ammonia carryover

Figure 4-7. Nitric oxide reductions and ammonia carryover with ammonia injection at 2 percent excess oxygen (Reference 4-56).

temperatures essentially no ammonia leaves unreacted (see Figure 4-7(b)). Figure 4-8 shows that for a given $(NH_3)/(NO)$ ratio, ammonia injection is more effective at higher initial NO levels. However, this trend is only signficiant at initial NO levels of less than 400 ppm. These factors are important considerations in assessing the tradeoffs between implementing only ammonia injection as a NO_x control or in combination with combustion modification techniques.

Byproduct pollutants from ammonia injection have been analyzed by Lyon and Longwell (Reference 4-57) who measured emissions of N_2O, CO, HCN, SO_3 and NH_4HSO_4 from gas- and oil-fired pilot scale combustion facilities. Emissions of N_2O were found to be limited to 2 moles N_2O for every 100 moles of NO reduced. Ammonia was not found to react with CO_2 to form CO. However, the presence of ammonia in the combustion effluent was found to inhibit the conversion of CO to CO_2. Therefore, this technique becomes a problem only if the concentration of CO in the flue gas is significant. In utility boilers this may not be the case, especially for gas- and oil-fired units. However, coal-fired boilers with higher CO levels may present a problem.

Cyanide can only form if unburned hydrocarbons are present in the flue gas. For normal operation of utility boilers, only a few ppm of HCN can be found.

Careful laboratory work has shown that ammonia injection does not produce additional SO_3 emissions (Reference 4-58). In fact, SO_2 levels remained unchanged during the injection stage. The main byproduct pollutant of concern is ammonium bisulfate. The unreacted NH_3 leaving De-NO_x reaction was found to combine with SO_3 and H_2O to form ammonium bisulfate. This substance forms a very corrosive liquid at 480K to 530K (400^oF to 500^oF). Thus it could potentially corrode sections of the boilers such as the air preheater and flue gas ducts if the concentration of ammonia bisulfate is significantly high. During full scale studies of an oil-fired boiler however, no evidence of additional corrosion was found (Reference 4-59).

Full scale application of the Exxon Thermal De-NO_x process has been reported for six gas- and oil-fired combustion sources in Japan affiliated with Exxon Corporation. Figure 4-9 shows that the average NO_x reduction reported with the ammonia injection technique is of the order of 50 percent.

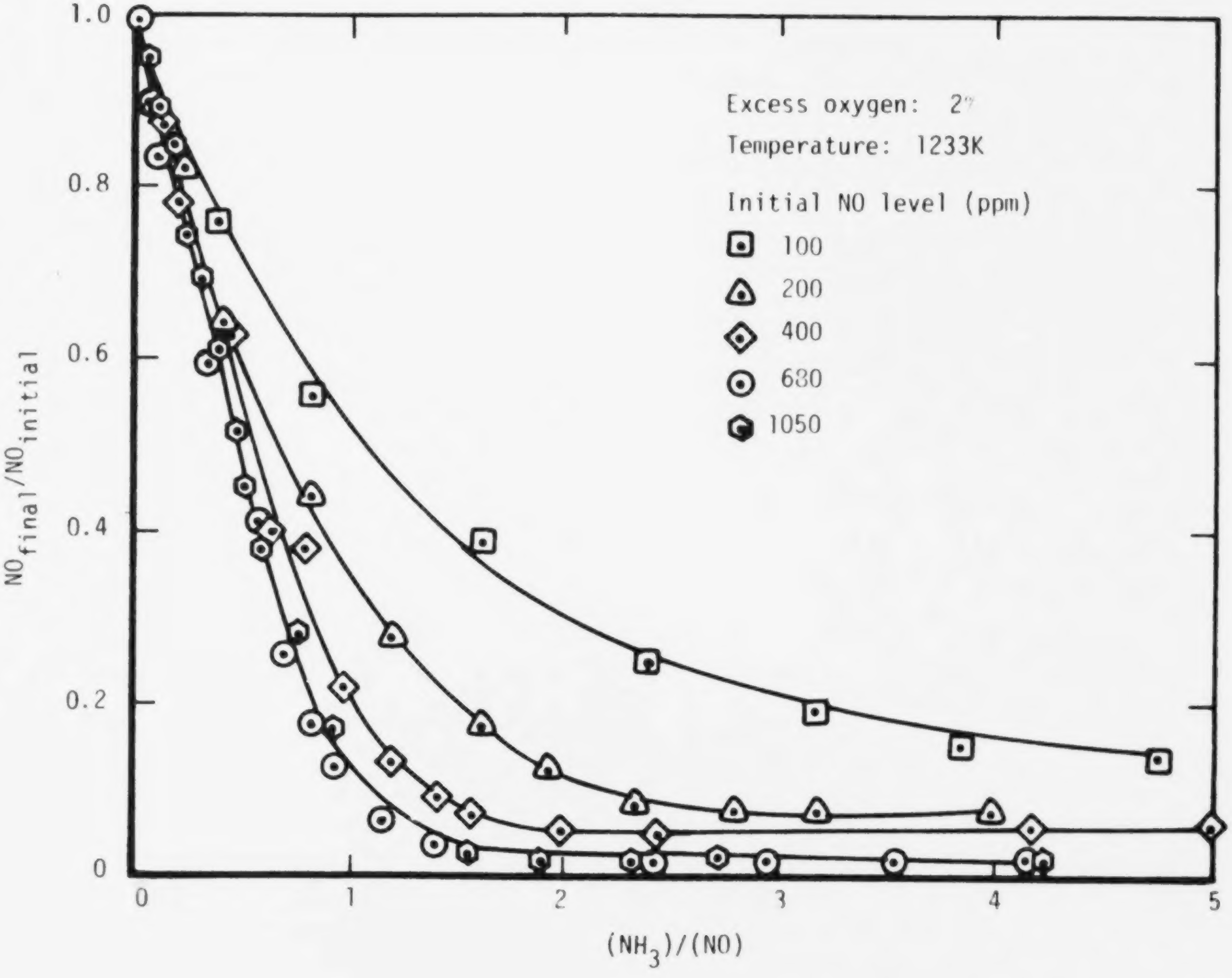


Figure 4-8. Effect of initial nitric oxide concentrations on NO reduction with ammonia injection (Reference 4-56).

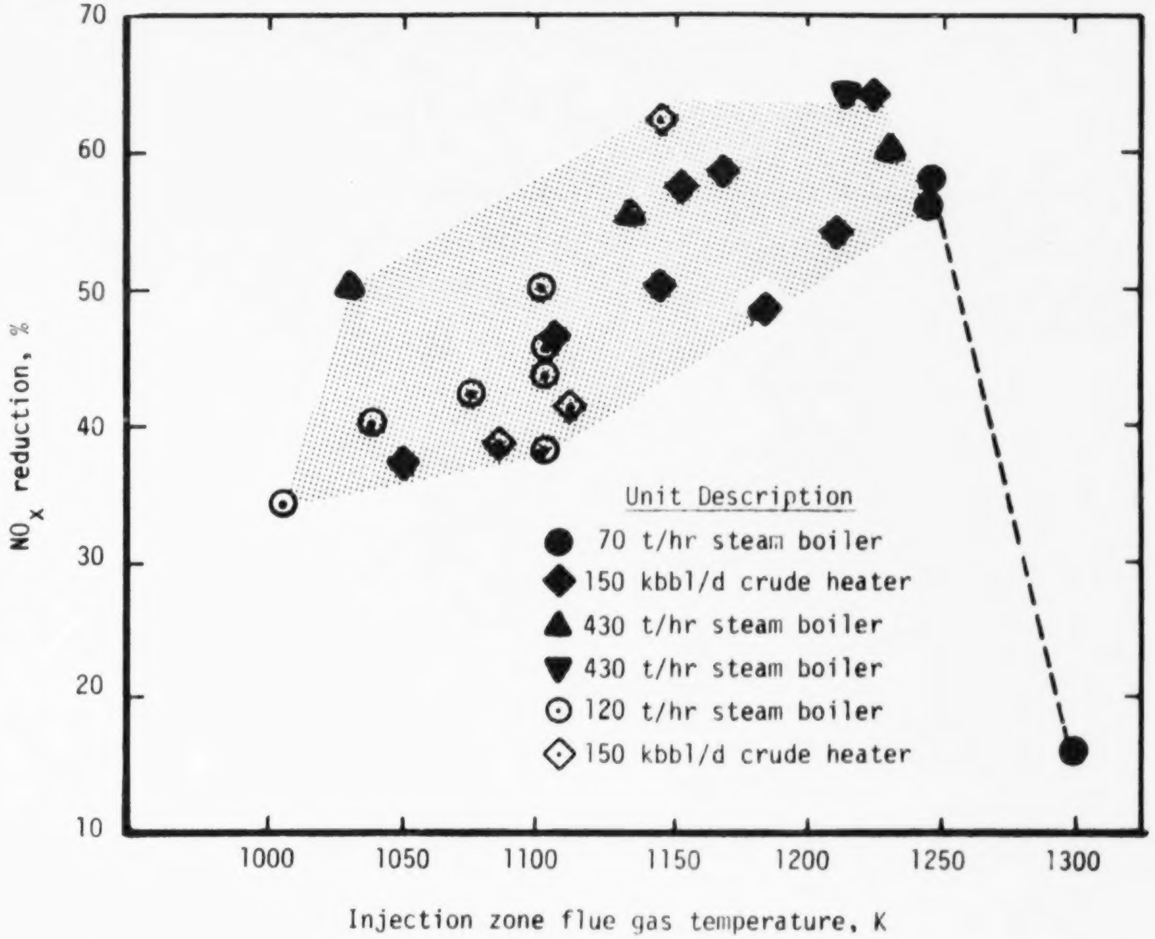


Figure 4-9. Performance of Thermal De-NO_x systems in commercial applications (Reference 4-55).

One other full scale combustion facility in the United States has been retrofitted with ammonia injection. NO_x emissions were reduced from 270 ppm to 80 to 120 ppm (Reference 4-59). Details of the process are not available.

The Thermal De-NO_x process for NO_x emission reduction shows a promising application for utility boilers, with potential NO_x reductions of 40 to 60 percent. However, full scale studies have been limited to gas and oil which are becoming less available in the utility fuel market. Pilot scale tests using ammonia injection on coal-fired furnaces have been completed by KVB under EPRI sponsorship (Reference 4-60). Basically the study confirmed the effectiveness of the technique as well as its potential limitations such as the narrow temperature window and possible ammonia byproduct emissions.

EPA has assessed the applicability and effectiveness of ammonia injection in two recent studies (References 4-61 and 4-62). The studies conclude that ammonia injection holds promise for additional NO_x reductions, 40 to 60 percent, in those air quality regions where stringent NO_x controls may be required. Ammonia injection could be applied as an add-on technology, in combination with conventional combustion modification techniques. However, a number of limitations need to be considered and evaluated before the process is retrofitted, especially for coal-fired boilers:

- Performance is very sensitive to flue gas temperature, and is maximized only within a 50K temperature gradient from the optimum temperature of about 1240K. This temperature sensitivity may require special procedures for load following boilers, such as multiple NH_3 injection grids.
- Performance is very sensitive to flue gas residence time at optimum temperatures. High flue gas quench rates are expected to reduce process performance.
- Costs of the process can be much higher than for other combustion controls
- Successful retrofit application is highly dependent on the geometry of convective section
- Byproduct emissions such as ammonium bisulfate might cause operational problems, such as air preheater fouling, especially in coal-fired boilers

- Ammonia emissions may be an environmental problem if the process is not carefully controlled

Exxon is currently investigating possible solutions to these potential problems. Ammonia injection can potentially offer a near term control option for achieving NO_x emission levels not obtainable with current state-of-the-art controls (Reference 4-62).

4.4 MINOR EMPHASIS CONTROLS

In this section, controls which were given minor emphasis in the present study are briefly discussed. These were treated in less detail because they were considered to have less promise for widespread application than those described above, for such reasons as energy penalties, high cost, or technical difficulties. However, flue gas treatment techniques are included here largely because they are being studied in greater depth in other efforts (References 4-63 and 4-64).

4.4.1 Reduced Air Preheat

Thermal NO_x production is strongly influenced by the effective peak temperatures in the combustion zone. Thus, any modification that lowers these temperatures, such as reducing the combustion air temperature, should lower NO_x emissions. Theory indicates that a 56K (100°F) decrease in air preheat temperature will result in an approximately 28K (50°F) reduction in the adiabatic combustion temperature, which in turn will decrease thermal NO_x formation by 27 percent (References 4-44 and 4-65). Since reduced air preheat does not significantly suppress fuel nitrogen conversion (Reference 4-66), it is expected that this control technique would be most effective on fuels, such as natural gas and distillate oil, which have low nitrogen content.

Reduced air preheat is potentially applicable to most utility boilers because these sources are equipped with regenerative air heaters which preheat combustion air. This method for controlling NO_x usually greatly lowers fuel economy, however. New designs to reduce stack gas temperatures, for example, and redesign of the convective section of a boiler for more heat absorption would be necessary to maintain efficiency.

Only limited field test data are available on the effect of reduced air preheat in utility boilers due to the severe efficiency penalty incurred with this method. Some field test results and discussions on reduced air preheat for utility boilers are available in References 4-67 through 4-69.

The data reported for coal firing showed varying trends, although a maximum reduction of 75 ppm (at zero percent O_2) per 56K reduction in air temperature was reported in one case (Reference 4-66). In general, NO_x reductions of about 50 percent for gas-fired boilers and 40 percent for oil-fired boilers can be expected with reduced air preheat, in contrast to the relatively small reductions in coal-fired boilers (Reference 4-77).

In summary, reduced air preheat reduces efficiency, and is therefore not considered a practical control technique for existing units. Design changes in new units, such as installing or enlarging an economizer, would be required to regain the waste heat which would otherwise be lost through the stack.

4.4.2 Water Injection

Water injection has been shown to reduce flame temperature and is widely used in gas turbines. Only recently has water injection been tried on utility boilers.

The Ormond Beach, steam generating units operated by Southern California Edison were tested with water injection to reduce NO_x (Reference 4-33). The boilers operating at 75 percent of full load (design capacity 800 MW) with 10 percent tertiary air, were emitting 400 ppm of NO when 0.6 kg of water per kg of oil was injected, the emissions were reduced to 228 ppm, a 43 percent reduction. Higher reductions were obtained with flue gas recirculation and water injection combined. For example, with 15 percent gas recirculation and injection of 0.2 kg of water/kg of oil, NO reduction of nearly 50 percent was achieved. Compared to flue gas recirculation, water injection imposes a large energy penalty. Water injection increased the minimum O_2 requirement and reduced boiler efficiency by 10 percent in the Ormond Beach case. The large efficiency loss due to water injection makes this technique unattractive to the utility sector.

In summary, water injection is not seen as a feasible NO_x reduction technique for utility boilers based on the large energy penalty incurred. Thus little current work with this technique is being performed on large steam generators.

4.4.3 Flue Gas Treatment

While combustion modification techniques seek to lower NO_x emissions by minimizing NO formation, flue gas treatment (FGT) processes involve post-combustion NO_x removal from the flue gas. Flue gas treatment has potential for use combined with combustion modifications when very high removal efficiencies are required (References 4-63, 4-64, and 4-76).

FGT has been applied to only a few commercial oil- and gas-fired boilers in Japan. No FGT installation for NO_x control on utility boilers exists in the United States as combustion modifications represent the most cost effective approach to achieving moderate NO_x reductions. However, combustion modifications alone may not be able to provide the degree of control necessary to meet future NO_2 ambient air quality standards. Thus EPA has initiated several demonstration projects to investigate the use of FGT in the U.S. (Reference 4-64).

FGT processes can be divided into two main categories: dry processes and wet processes. Dry processes reduce NO_x by catalytic reduction and operate at temperatures between 570 to 700K (570 to 800°F). Wet systems are generally either oxidation/absorption or absorption/reduction processes, both operating in the 310K to 320K (100 to 120°F) range.

Among the many dry process variations, selective catalytic reduction (SCR) using ammonia has been perhaps the most successful. Over 50 percent NO_x, and often up to 90 percent reductions have been claimed using such processes. However, plugging of the catalyst bed and fouling of the catalyst itself are major operational concerns, especially with coal firing. Moreover, use of SCR has raised concerns in that any ammonia left in the flue gase may combine with existing SO_3/SO_2 to produce a visible plume, and byproducts, such as ammonium bisulfate, which are corrosive to boiler equipment.

Wet FGT processes utilize more complex chemistry than dry processes. In the oxidation/absorption processes, strong oxidants such as ozone or chlorine dioxide are used to convert the relatively inactive NO in the flue gas to NO_2 or N_2O_5 for subsequent absorption. In the absorption/reduction processes, chelating compounds, such as ferrous ethylenediaminetetracetic acid are required in the scrubbing solution to trap the NO. However, because wet processes rely on absorption, most of them create troublesome byproducts such as nitric acid, potasium nitrate, ammonium sulfate, calcium nitrate, and gypsum which may have little commercial value. In addition, the high cost of an absorber and an oxidant or chelating agent is likely to be prohibitive for flue gases with high NO_x concentrations.

In general, the dry FGT techniques used in Japan can probably be applied to gas- and oil-fired sources in the U.S. However, the applicability of dry processes to coal-fired boilers remains to be demonstrated. Wet processes are less well developed and costlier than dry FGT processes. However, wet simultaneous, as well as dry simultaneous NO_x/SO_x processes warrant further investigation. In any case, more field tests are needed to determine the costs, secondary effects, reliability, and waste disposal problems. Flue gas treatment holds some promise as a control technique for use when high NO_x removal efficiencies are necessitated by stringent emission standards. However, compared to combustion modifications FGT is considerably more expensive.

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SECTION 5

NO_x CONTROL CHARACTERIZATION: EMISSION CORRELATION

Based on the general NO_x formation concepts discussed in Section 4, it is evident that the basis for combustion modification NO_x controls can be eventually traced back to chemical kinetics, turbulent mixing, and heat transfer. However, incomplete understanding of the combustion phenomena as well as insufficient data have prevented researchers from fully characterizing NO_x formation and control in utility boilers. Therefore, from a practical control point of view, it would be valuable to relate NO_x emissions to gross overall furnace parameters, such as surface heat release rates, for which there are sufficient data from full scale utility boiler tests. These overall furnace parameters can, in turn, be explained in terms of such local or fundamental parameters as temperature and combustion regimes. This information can be used to evaluate the basis and effectiveness of various NO_x control techniques. Furthermore, it can aid in the cost-effective design of new controls as well as in providing direction for future research efforts since key boiler/burner design and operating variables would have been identified.

However, it should be noted that the NO_x emission correlations presented in this study are not intended to be definitive nor predictive. Rather they are meant only to present general trends and highlight important burner and boiler design and operating parameters. There is insufficient data available to warrant in-depth interpretation.

This section begins with a review of previous NO_x modeling efforts Section 5.1 then proceeds to a development of an interboiler NO_x correlation model in Section 5.2. The available data base of control tests, spanning several test programs on many individual boilers, is also discussed. Section 5.3 presents the results of applying this correlation model to some of the major boiler/fuel classifications, as data permitted. The key boiler/burner design and operating variables and fuel characteristics affecting NO_x formation are identified, and the results are interpreted in the light of fundamental combustion theory and knowledge of boiler operating practice. Finally, Section 5.4 summarizes the findings.

5.1 PREVIOUS NO_x MODELING EFFORTS

In recent years, numerous investigators have attempted to predict NO_x formation in utility boilers, witn varying degress of success. In general, the studies have fallen into one of two broad categories: purely empirical approaches to NO_x prediction based on available field test data, and more fundamental approaches relying more heavily on heat and mass transfer, flowfield, and combustion fundamentals. Some of the more significant efforts are highlighted below.

Perhaps the most comprehensive of the fundamental models is that developed by Combustion Engineering (CE) and reported by Bueters, et al. (Reference 5-1) and Habelt and Selker (Reference 5-2). Combustion Engineering spent several years developing a performance code to predict NO_x emissions from tangentially fired utility boilers. Basically, their model calculates the axial temperature/time history of combustion products, then introduces NO_x generation via the Zeldovich mechanisms. The calculation proceeds by dividing the furnace into "slices" and solving the conservation equations for mass (including the combustion reactions), momentum (flowfields), and energy in each slice.

Although this model is quite detailed and was designed to be fundamental, it still relies heavily on actual data to determine the numerous adjustable parameters incorporated. For example, although the model accounts for vertical recirculation of the gaseous products, it cannot determine the length of the recirculation region nor the length and position of the heat release zone. In addition, the model needs as input a "gas emissivity operator." Because these quantities depend upon the operational mode of the boiler, e.g., load, fuel nozzle tilt, and excess air level, data on the length and position of the heat release zone and gas emissivity still must be correlated empirically against boiler operational variables.

In addition, since the CE model incorporates only Zeldovich kinetics, it has inadequate provisions for predicting fuel NO_x generation. Thus, predictions for units burning high nitrogen content fuels, such as high nitrogen oil and coal, are uncertain. The code predicts NO_x to within 10 percent for gas-fired units, but only to within 15 percent for oil-fired units, and is inadequate for coal-fired units. Perhaps even the good agreement for gas-fired boilers is fortuitous since the Zeldovich mechanism employed is still inaccurate in that it does not account for superequilibrium N and O concentrations. Nonetheless, the model has proved quite useful as a predictive and design tool.

In another effort, Quan, et al., (Reference 5-3) attempted to derive NO_x scaling relationships for industrial combustors by developing dimensionless groups from the basic conservation equations for momentum, energy, and species concentration. However, several simplifying assumptions had to be made for their model. First, Quan, et al., employed a single characteristic length to represent the composite of burner and firebox dimensions important in NO_x formation. Second, the radiation heat loss from the flame in the NO_x formation region was greatly simplified. Also, the kinetic scaling neglected the effects of turbulent mixing and hydrocarbon/NO_x coupling in NO_x formation. The results predict NO_x emissions as proportional to combustor characteristic length, which is unrealistic. Thus, such simple scaling exercises are limited in their abilities to model highly coupled phenomena such as NO_x formation.

Quan, et al., (Reference 5-4) also attempted to predict NO_x formation by solving the governing partial differential equations for a 2-D combustor. 2-D elliptic flow code was used with approximate models for turbulence, radiation heat transfer, and kinetics of hydrocarbon oxidation and NO_x formation. Unfortunately, the results were disappointing even for the idealized situation studied by the author. NO_x predictions were highly sensitive both to the finite difference grid selected and to the form of the physical/chemical models used. Also, the grid distribution required to compute the near burner events without large truncation errors was impractical. Efforts by McDonald, et al., also on a 2-D combustor, encountered similar difficulties (Reference 5-5).

Subsequent work by Quan and other investigators has been limited as far as application to practical combustors. The phenomena to be modeled are quite complex. First, it is thought that turbulent mixing can dominate the combustion and NO_x formation rates in the primary flame zone. Second, the hydrocarbon oxidation kinetics are strongly coupled to NO_x formation in the near burner region, and simple Zeldovich kinetics are inadequate. Also, for oil or coal combustion, the droplet/particle combustion rate is strongly coupled to luminous radiation heat transfer. Although predicting these phenomena is possible in idealized lab-scale situations, it is beyond current capability for practical combustors where the mixing, chemistry, and heat transfer are strongly coupled. Thus, predicting NO_x formation in practical combustors from solutions of basic conservation equations is currently not possible.

In a more recent modeling effort, Dykema (References 5-6 and 5-7) adopted a semiempirical approach employing a furnace model and a simple Zeldovich mechanism for thermally generated NO_x, coupled with a largely empirical model for the conversion of fuel bound nitrogen. Unfortunately, the result was not very useful as a predictive tool. In fact, the model often predicts wrong phenomena. For example, parametric variation of excess air in Dykema's correlation showed a slight increase in NO_x with decreased excess air. Also parametric variation of the location of burners out of service rows indicated that middle rows out of service would give the lowest NO_x emissions in gas-fired boilers, while bottom rows out of service would be preferable in oil-fired units. Generally, these conclusions do not concur with field experience.

In addition to the more fundamental models attempted above, several empirical approaches to test data correlation have been pursued in recent years. Bartok, et al., (Reference 5-8) and Crawford, et al., (Reference 5-9) used a second order multiple regression analysis to correlate flue gas NO_x concentrations with a limited number of boiler operating variables. Because boiler design properties were not considered as independent variables, Bartok's and Crawford's analyses were restricted to the individual boilers and loads studied.

Hollinden, et al., (References 5-10 and 5-11) correlated NO_x emissions with the same boiler operating variables used by Bartok. Again, the empirical analysis was performed on an individual boiler basis, thus limiting the applicability of the correlation found. In addition, in the earlier study (Reference 5-10), the author incorporated combustion staging only as either "on" or "off" and did not allow continuous variation of the staging parameters. In their later study (Reference 5-11), they included only uncontrolled NO_x emissions in their analysis, thus limiting the regression equations to predicting NO_x levels only under normal firing conditions.

Cato, et al., (Reference 5-12) have also performed an empirical study correlating uncontrolled NO_x emissions from industrial size boilers with boiler design and operating variables. Although their data base was quite diverse, covering more than a single boiler, their analysis was limited to uncontrolled NO_x emissions. In addition, industrial, not utility, boilers were studied.

The above review was intended to highlight some of the difficulties in attempting to model NO_x emissions on a fundamental basis as well as to indicate a few of the practical limitations of reported empirical models. The efforts of the investigators cited above, though admirable, encountered monumental difficulties when attempting to relate real world utility boiler combustion to fundamental parameters. The following section presents the NO_x Emission Correlation Model, a multiple regression analysis developed in this study. The model is a crude attempt to correlate emissions from a host of actual operating utility boilers to some common burner and boiler design and operating variables. The intent is by no means fundamental, but rather to highlight general trends.

5.2 NO_x EMISSION CORRELATION MODEL

The formation of NO_x in utility boilers is a complex and, at the present time, imperfectly understood phenomena. Thus, although some fundamental NO_x formation models are available, as discussed above, especially for thermal NO_x, these models usually only relate NO_x generation to such fundamental combustion variables as stoichiometry flame temperature and residence time of gases in the flame zone. Because the flow in the furnace burner zone of an actual combustion source like a utility boiler is extremely complicated, it is quite difficult to determine the quantitative changes in these fundamental parameters resulting from given operational or design changes. Thus, it is quite difficult to apply these fundamental models to NO_x production in actual combustion systems.

Consequently, a more empirical approach to NO_x correlation was chosen in this study. From the point of view of the boiler operator or designer, it is desirable only to establish which operational and design variables are important in controlling NO_x emissions, and to obtain estimates on how much NO_x levels will change with given changes in those variables. Thus, a model based on multiple regression of existing data on boilers would correlate NO_x emissions to specific boiler variables and serve these desired ends. Such a model based on data from boilers under actual operating conditions would be expected to reproduce the average response of field boilers, in general, if the sample chosen for study is representative of the field population. The following sections outline the development of the correlation algorithm employed and the data base used for analysis. It is noted that since the data base is limited, the model should only be examined for general trends. Indeed it should not be considered predictive, but interpolative.

5.2.1 Procedures

A large number of operational and design variables may be postulated to affect NO_x formation. A regression analysis can help in screening these variables to determine which ones are most significant in controlling NO_x. Moreover, as many of the variables are highly intercorrelated, the analysis should incorporate a selection mechanism whereby only the variables most strongly correlated with NO_x emissions enter the regression and the other intercorrelated variables are excluded. The model would, therefore, identify the important independent variables and quantify the change in NO_x emissions due to specified changes in the magnitude of the variables.

A second order regression model was used to fit the NO_x emission data compiled as discussed below. A second order model was required because NO_x formation mechanisms are usually nonlinear with the fundamental parameters, therefore, a first order model does not correlate the data very accurately. Also, as there is expected to be some degree of interaction between the effects of the variables, cross product terms need to be included in the model. A second order regression model includes quadratic and cross product terms. The predictive equation in such a model takes the following form:

$$y = a_0 + a_1x_1 + \dots + a_{11}x_1^2 + a_{22}x_2^2 + \dots + a_{12}x_1x_2 + \dots$$

where y is the response variable, in this case the NO_x emission level x_1, x_2 ... are the independent boiler variables and a_0, a_1, ... are the coefficients to be determined. The coefficients are determined by obtaining the best fit to the data as defined by minimizing the sum of the squares of the distance between the predicted values and the data (least squares fit).

By choosing a second order model, it was assumed that terms of order higher than quadratic are not important in the analysis, and that exclusion of cross product terms with more than two variables does not significantly affect the accuracy of the prediction. A third order model could have been constructed in a fashion similar to the second order model, but the number of terms required would make the analysis too long and unwieldy.

Some of the assumptions underlying the regression analysis are that the distribution of each variable is normal, and their joint distributions are also normal. Also, all variables must be homoscedastic; that is, the variance of each variable must be uniform over the sample space. Other assumptions inherent in the analysis are that: (1) no important boiler variables were overlooked by the investigators, (2) the data selected for use in the regression were representative of typical boilers and operating conditions, (3) the data reported were accurately measured and reported, and (4) the data from different boilers and different tests all had comparable errors of measurement.

In one case, a second order model did not yield the desired degree of precision in predicting data. In that instance, a logarithmic model was used. The logarithm of NO_x emissions are correlated linearly to the logarithm of the dependent variables, and the predictive equation then takes the form:

$$\log y = a_0 + a_1 \log x_1 + a_2 \log x_2 + a_3 \log x_3 + \dots$$

which is equivalent to

$$y = c \; x_1^{a_1} \; x_2^{a_2} \; x_3^{a_3} \; \ldots$$

The assumptions underlying a logarithmic model are similar. Specifically, the logarithms of the variables are assumed normally distributed and the variances based on the logarithms of the variables are homoscedastic. It is very unlikely that these conditions will ever be met in practice. But, the procedure can be justified as useful in screening variables and providing guidelines on the expected magnitude of changes in NO_x emissions due to changes in boiler variables.

The multiple regression analysis was performed using the stepwise regression procedure (References 5-13 and 5-14). In this procedure variables are introduced into the correlation one at a time in order of most significant correlation. In the specific procedure employed, a first order linear multiple regression analysis, using the stepwise procedure, was first carried out to identify the seven most important variables. Second order analysis was then performed.

As each new variable was introduced into the regression, the multiple correlation coefficient of the regression up to that point was calculated. The stepwise procedure was terminated when the increase in the multiple correlation coefficient with addition of new variables became sufficiently small. As the multiple correlation coefficient is directly related to the square of the variation explained by regression, this criterion tends to inhibit variables which do not contribute substantially to decreasing the standard error of the estimate from entering the regression.

Multiple regression equations obtained in this manner were examined to check whether NO_x emissions predictions were within desired degrees of accuracy. If sufficient precision could not be obtained with a second order model, a logarithmic model was employed. Thus, in one case the logarithmic model yielded better predictive correlations than the second order model.

5.2.2 Data Base

For emissions correlations through the procedure described above, uncontrolled and controlled NO_x combustion data were obtained from a total of 61 boiler firing type/fuel combinations. Table 5-1 breaks out the test data combinations employed. Data gathering was limited to tangential, horizontally opposed and single wall firing types as these were the most extensively tested. Fortunately, a representative population was treated because these firing types represent approximately 87 percent of the current installed utility steam generating capacity. NO_x emissions from turbo furnace, cyclone, vertical, and stoker furnaces were not analyzed in depth because published emissions data from these boilers were very limited.

Emissions data were assembled from emissions field test programs sponsored by EPA and by several private utility companies. In many cases, previously unreported test data were incorporated. References 5-6, 5-8 through 5-11, and 5-15 through 5-19) supplied the test data assembled.

Several specific units were tested in more than one program. In these instances each individual program was considered as a separate unit. Therefore, the totals in Table 5-1 include boilers that were tested more than once during different programs. The additional sets of emissions data from these units were considered valuable in the present analysis because different levels of NO_x control were usually achieved from test program to program. In addition, baseline and controlled boiler operating conditions varied slightly between separate test programs on the same boiler, thus providing more representative average operating conditions and emission levels.

Table 5-2 itemizes the actual test points incorporated into the emissions data base. The total of 563 tests represents approximately 25 percent of the total number of tests reported in the various test programs. The table shows that the largest number of selected tests, comprising 54 percent of the data, were on coal-fired utility boilers. Gas-fired and oil-fired boilers were studied in 24 and 22 percent of the test points, respectively. The single most studied category was tangential coal-fired steam generators with 147 individual tests.

Six single control techniques were considered in the analysis:

- Low excess air (LEA)
- Overfire air (OFA)
- Biased burner firing (BBF)
- Burners out of service (BOOS)

TABLE 5-1. FIELD TEST PROGRAM DATA COMPILED

Fuel	Firing Type			Total
	Tangential	Opposed Wall	Single Wall	
Coal	13	6	10[a]	29
Oil	2	7	7	16
Natural Gas	1	8	7[b]	16
Total	16	21	24	61

[a] Includes two wet bottom furnaces

[b] Includes one unit originally designed for coal firing with a wet bottom furnace

TABLE 5-2. INDIVIDUAL TEST POINTS CORRELATED

			Single Controls				Combined Controls[a]				Total
Firing Type	Fuel	Baseline[b]	LEA[c]	OSC[d]	FGR[e]	Low Load[f]	Low load + OSC	Low Load + FGR	OSC + FGR	Low Load + OSC + FGR	
Tangential	Coal	21	29	46	--	24	27	--	--	--	147
Opposed Wall	Coal	8	11	11	7	7	5	1	2	--	52
Single Wall	Coal	18	23	29	--	19	19	--	--	--	108
Tangential	Oil	1	--	1	--	1	1	1	--	1	6
Opposed Wall	Oil	6	5	11	2	7	7	5	2	11	56
Single Wall	Oil	4	6	5	4	8	6	10	10	8	61
Tangential	Nat gas	1	1	--	2	2	1	5	1	--	13
Opposed Wall	Nat gas	7	9	18	--	13	13	3	3	8	74
Single Wall	Nat gas	5	4	9	2	7	7	3	4	5	46
All Boilers	All fuels	71	88	130	17	88	86	28	22	33	563

[a] Low excess air also generally employed

[b] Baseline = no controls applied; boiler load near or at maximum rating; excess air at normal or above normal settings

[c] LEA = low excess air setting

[d] OSC = off stoichiometric combustion (includes: biased burner firing, burners out of service, overfire air)

[e] FGR = flue gas recirculation; generally includes low excess air setting

[f] Load less than 80 percent of maximum continuous rating (MCR)

- Flue gas recirculation (FGR)
- Load reduction

Data on applying other NO_x reduction techniques, such as water injection, mill fineness setting, and reduced air preheat, were occasionally reported. However, these were not included in correlations because data were limited, and these techniques are considered of lesser priority for study in the present analysis. At the time this correlation analysis was performed, little boiler data from coal-fired units retrofitted with low NO_x burners were available (References 5-15, 5-20, and 5-21). These data were too limited for statistical treatment. In addition, the correlation algorithm derived included no single variable able to distinguish between conventional circular and dual register burner designs.

Virtually all tests reported in which single controls or combinations of these controls were applied in various degrees were included in the data base. However, test points were excluded from the analysis if they failed two general selection criteria:

- Were NO_x reductions representative of the unit tested?
- Were other boiler operating parameters, e.g., register settings held nominally constant within normal ranges?

For example, test points were rejected as failing the first criterion if the test crew reported inconsistencies between these points and the remainder of the test program. Test data describing lowest NO_x levels achieved on a given unit were in general included. However, if the test report noted that operation at these levels was deemed unsafe by plant personnel, the data were rejected.

Similarly, test data were excluded if other boiler operating parameters, not explicitly treated in the correlation algorithm, were not held to nominally constant values. For example, several test series investigated the effects of burner register settings on NO_x emissions. Changing register setting causes variations not only in burner swirl but also in airflow through the burner. However, since register setting was not treated explicitly in the emissions correlation model, these test series were excluded from the data base. Only tests with "normal" and nominally constant register settings were included. Similarly, tests on tangential units which varied burner or overfire air port tilt were excluded.

Finally, for BOOS tests, only data taken with burners in the top rows removed from service were included in the correlation data base. All other BOOS patterns were disregarded.

Based on the above, only about 25 percent of the total reported test data were suitable for inclusion in the assembled correlation data base. Of the data excluded, much of it was due to insufficient information, e.g., the boiler's heat release rate could not be obtained. As Table 5-2 shows, a total of 71 baseline tests were chosen to represent normal, uncontrolled boiler operating conditions. For comparisons of the effectiveness of the individual NO_x controls studied, 88 LEA firing tests, 130 off stoichiometric combustion (OSC) tests, 17 FGR tests, and 88 load reduction (load at less the 80 percent of unit MCR) tests were included. Off stoichiometric combustion in its various applications (BBF, BOOS, and OFA) was by far the most extensively tested combustion modification technique. In contrast, test data for FGR as a single NO_x control were insufficient for a good statistical analysis of the effects of this technique.

The purposes of performing the NO_x correlation analyses were twofold. Of course, good statistical evaluations of the effectiveness of commonly applied combustion controls singly and in combination, were desired. But regression relationships between NO_x emissions and more fundamental combustion, boiler design, and operating parameters were also sought through the model, to highlight general trends.

Thus, specific data on a set of design and operating variables associated with each test point in the data base were needed to allow correlation relationships to be obtained. These correlation variables used in the analyses fell into three categories:

- Boiler operating variables
- Boiler design variables
- Fuel properties

Boiler Operating Variables

Correlation parameters in this category are the macroscopic combustion variables describing boiler operation, which are altered when a combustion control is applied. The specific variables used in the present analysis included:

- Overall furnace fuel/air stoichiometry
- Stoichiometry at active burners
- Percent flue gas recirculated
- Firing rate (as percent MCR)
- Percent burners firing
- Heat input per active burner

For example, an LEA application can be trivially considered as a change in overall furnace stoichiometry. Similarly, applying OFA alters burner stoichiometry and perhaps also overall stoichiometry if higher overall excess air levels are required. Burners out of service firing elicits similar changes while also altering percent burners firing. Flue gas recirculation is applied by changing the percent gas recirculation variable. Load reduction is obviously accompanied by changes in firing rate and oftentimes heat input per active burner and overall stoichiometry.

Boiler Design Variables

The boiler design variables considered in the regression analysis included:

- Nameplate maximum continuous rating (MCR)
- Volumetric heat release rate
- Surface heat release rate
- Heat input per active burner
- Number of burners
- Number of furnaces
- Number of division walls

Table 5-3 lists the ranges and average values encountered for each of these variables. Boilers of the same fuel and firing type were grouped together in the correlation analysis.

Data on burner zone surface heat release rate were generally unavailable for the test reports cited. This is unfortunate since NO_x emission levels are expected to be stronger functions of this variable than of the more global overall heat release rate (Reference 5-22). In fact, adjusting this variable alone allows a significant degree of NO_x control for gas- and oil-fired boilers. Still, use of the overall

TABLE 5-3. BOILER DESIGN VARIABLES CONSIDERED

Equipment Type	Fuel	Maximum Continuous Rating, MW[a]		Volumetric Heat Release Rate, kW/m^3 (10^3 Btu/ft^3-hr)[b]		Surface Heat Release Rate, kW/m^3 (10^3 Btu/ft^{2}hr)[b]		Heat Input per Active Burner, MW (10^6 Btu/hr)[b]		Total No. of Burners		Range in Number of Furnaces	Range in Number of Division Walls
		Range	Average	Range	Average	Range	Average	Range	Average	Range	Typical Number		
Tan-gential	Coal	125-800	430	116-159 (11-15)	139 (13)	78-466 (25-148)	228 (72)	13-75 (45-261)	40 (139)	16-64	32	1-2	0
	Oil	66-320	193	289-310 (28-30)	300 (29)	349-541 (111-172)	443 (141)	11-38 (38-133)	24 (85)	8-24	16	1-2	0
	Natural Gas	320	320	289 (28)	289 (28)	541 (172)	541 (172)	38 (133)	38 (133)	24	24	2	0
Opposed Wall	Coal	218-820	580	134-178 (13-17)	157 (15)	228-312 (72-99)	259 (82)	33-86 (115-299)	49 (170)	20-54	34	1-2	0-1
	Oil	220-480	320	255-297 (25-29)	270 (26)	204-625 (65-199)	422 (134)	26-81 (90-282)	44 (153)	12-24	20	1	0-1
	Natural Gas	220-600	350	152-287 (15-28)	254 (25)	204-604 (65-192)	395 (126)	25-63 (87-219)	42 (146)	12-36	22	1	0-1
Single Wall	Coal	100-340	200	138-242 (13-23)	196 (19)	110-455 (35-145)	236 (75)	21-55 (73-191)	30 (105)	16-24	18	1-2	0-1
	Oil	80-250	190	198-299 (19-29)	250 (24)	248-778 (79-247)	343 (109)	22-43 (77-150)	35 (122)	12-24	14	1-2	0-1
	Natural Gas	80-315	200	181-282 (18-27)	232 (22)	248-324 (79-103)	265 (84)	21-43 (73-150)	33 (115)	12-24	16	1-2	0-1
All Boilers	Coal	100-820	430	116-242 (11-23)	164 (16)	78-466 (25-148)	241 (76)	13-86 (45-299)	40 (138)	16-64	28	1-2	0-1
	Oil	66-480	234	198-310 (19-30)	273 (26)	204-778 (65-247)	402 (128)	11-81 (38-282)	34 (118)	8-24	28	1-2	0-1
	Gas	80-600	290	152-289 (15-28)	258 (25)	204-604 (65-192)	400 (127)	21-63 (73-218)	38 (132)	12-36	20	1-2	0-1
	All Fuels	66-820	310	116-310 (11-30)	232 (22)	78-778 (25-247)	348 (110)	11-86 (38-299)	37 (129)	8-64	22	1-2	0-1

[a] Electrical output
[b] At maximum continuous rating

parameter, for which data were generally available, did allow reasonably good NO_x correlation.

Heat input per active burner could also be considered a boiler operating parameter but was grouped here with design variables for convenience. As Table 5-3 shows, heat input per active burner varied in the data base from 11 to 86 MW. Horizontally opposed boilers in general recorded the highest values, probably because of the generally greater unit size, hence burner size, of these units. The value of this variable can be changed when applying biased burner firing, burners out of service, and load reduction. It should be noted, though, that load reduction can be accomplished by totally removing burners from service, in which case heat input per active burner could remain unchanged.

The number of furnace division walls was introduced as a design variable as part of a crude attempt to account for gross changes in furnace mixing patterns and burner zone surface heat release rate. The use of dividing water walls allows boiler designs with smaller surface heat release, at a relatively constant volumetric heat release rate. Ideally, effects of division walls on NO_x emissions would be picked up in the regression through these two variables directly. However, since these water walls generally separate the furnace only part of the way up to the convective passes, they also affect burner zone heat release rate at constant overall heat release rate. In addition, gas mixing patterns are altered from units of similar size, but of divided design, with corresponding effects on NO_x emissions.

For similar reasons, the number of furnaces was included as a correlation variable. Twin furnace design is most prevalent in larger tangentially fired units, though it is occasionally found with other firing types. It should be noted here, though, that two potentially important boiler design variables known to affect NO_x emission levels were not included in the correlation analysis because the data were not available. These are burner spacing and distance between the top burner level and the OFA ports. Both of these variables can have significant effects on NO_x production in a given unit by affecting flame interactions, gas mixing, and heat absorption in the burner zone. Furthermore, in BOOS and OFA applications, these variables will affect first and second stage residence time and separation. Unfortunately, these data were unavailable for most units tested in the test reports used in compiling the emissions data. Thus, they were not included in the analysis.

Fuel Properties

The fuel variables considered in the correlation analysis were nitrogen content, moisture content (coal only), and heating value. Unfortunately, the information on these fuel properties was not always available for each test point. In cases where fuel analyses were sparse at the individual run level, they were assumed constant throughout a series of tests on a specific boiler.

Table 5-4 lists the fuel properties considered in the present analysis and their average values. Fuel nitrogen for all coals tested varied by a factor of 3 from 0.62 to 1.84 percent by weight. Even though this represents a significant range in fuel nitrogen content, NO_x emissions were found not to be significantly affected by fuel nitrogen content.

Moisture content of coals also varied significantly from 1.14 to 36.4 percent. This is to be expected since coal types used in various tests varied from the low moisture content Eastern bituminous to the high moisture content Western sub-bituminous and lignite coals. Coal moisture content was also not found to affect NO_x emissions.

5.3 NO_x EMISSION CORRELATION RESULTS

In this section, the results of applying the correlation model to the data base of test results are discussed. Key boiler design and operating variables, burner characteristics, and fuel properties which affect NO_x formation are identified. The basis and effectiveness of the various NO_x control techniques are reviewed. These results are further discussed in the light of fundamental combustion principles and boiler operating practice.

The major boiler firing types, tangential, single wall, and opposed wall fired, with the principle fuels, coal, oil, and gas were treated. However, tangential oil- and gas-fired boilers were not considered in the correlation study as the data were insufficient for a statistical analysis.

5.3.1 Tangential Coal-Fired Boilers

A multiple regression analysis was carried out on tangential coal-fired boilers. Data were analyzed for 147 tests carried out on a

TABLE 5-4. PROPERTIES OF FUELS FIRED

Equipment Type	Fuel	Fuel Nitrogen, Percent by Weight		Fuel Moisture, Percent by Weight		Heating Value[a], MJ/kg (10^3 Btu/lb)	
		Range	Average	Range	Average	Range	Average
Tangential	Coal	0.6-1.6	1.2	3.4-31.9	12.5	19.0-32.3 (8.19-13.9)	27.2 (11.7)
	Oil	0.3-0.6	0.5	--	--	NA	NA
Opposed Wall	Coal	1.0-1.8	1.3	1.1-36.4	7.2	24.4-31.6 (10.09-13.57)	28.3 (12.2)
	Oil	0.2-0.4	0.3	--	--	43.7-45.8 (18.8-19.7)	44.2 (19.0)
Single Wall	Coal	0.8-1.5	1.3	4.5-28.9	8.9	23.0-32.8 (9.9-14.1)	28.8 (12.4)
	Oil	0.2-0.3	0.3	--	--	43.7-45.6 (18.8-19.6)	44.7 (19.2)
All Boilers	Coal	0.6-1.8	1.3	1.1-36.4	9.5	19.0-32.8 (8.19-14.1)	28.1 (12.1)
	Oil	0.2-0.6	0.3	--	--	43.7-45.8 (18.8-19.7)	44.4 (19.1)

[a] Dry basis

total of 13 boilers. The data included 21 tests performed under baseline conditions with the rest conducted under low NO_x conditions. Low NO_x techniques tested included LEA, OSC, low load and a combination of low load and OSC.

For tangential coal-fired boilers, the following equation correlates the data with a correlation coefficient of 0.87, i.e., 75 percent of the variance is explained by the regression:

$$y = 184 + 1.09 \times 10^{-7}(x_1)(x_2) - 1.67 \times 10^{-5}(x_1) + 2.49 \times 10^{-6}(x_3)(x_4) + 6.54 \times 10^{-14}(x_1)^2$$

where

y = NO_x emissions (ppm dry at 3 percent O_2)
x_1 = Heat input per active burner (W)
x_2 = Stoichiometry to active burners (percent stoichiometric air)
x_3 = surface heat release rate (W/m^2)
x_4 = Furnace stoichiometry (percent stoichiometric air)

From the regression equation it is seen that burner stoichiometry and heat release rate are the most important parameters governing NO_x emissions in these boilers. This is in agreement with fundamental combustion principles as stoichiometry affects both thermal and fuel NO_x while heat release should mainly affect thermal NO_x. The equation indicates that, in general, NO_x emissions will be reduced by decreasing both stoichiometry and heat release, which is also consistent with theory.

A graphical representation of how NO_x emissions vary with surface heat release rate and burner stoichiometry is shown in Figure 5-1. The parametric lines in the figure are generated from the regression equation by allowing surface heat release to vary while fixing the burner stoichiometry at the values shown beside the curves. All other variableswere held constant at their mean values, except for furnace stoichiometry which was taken equal to burner stoichiometry for non-OSC operation, and fixed at some lower limit (typically 120 percent) for OSC operation. The parametric lines are seen to match reasonably closely with the data points. The reduction in NO_x emissions with reduced burner stoichiometry and surface heat release rate is clearly evident from the figure.

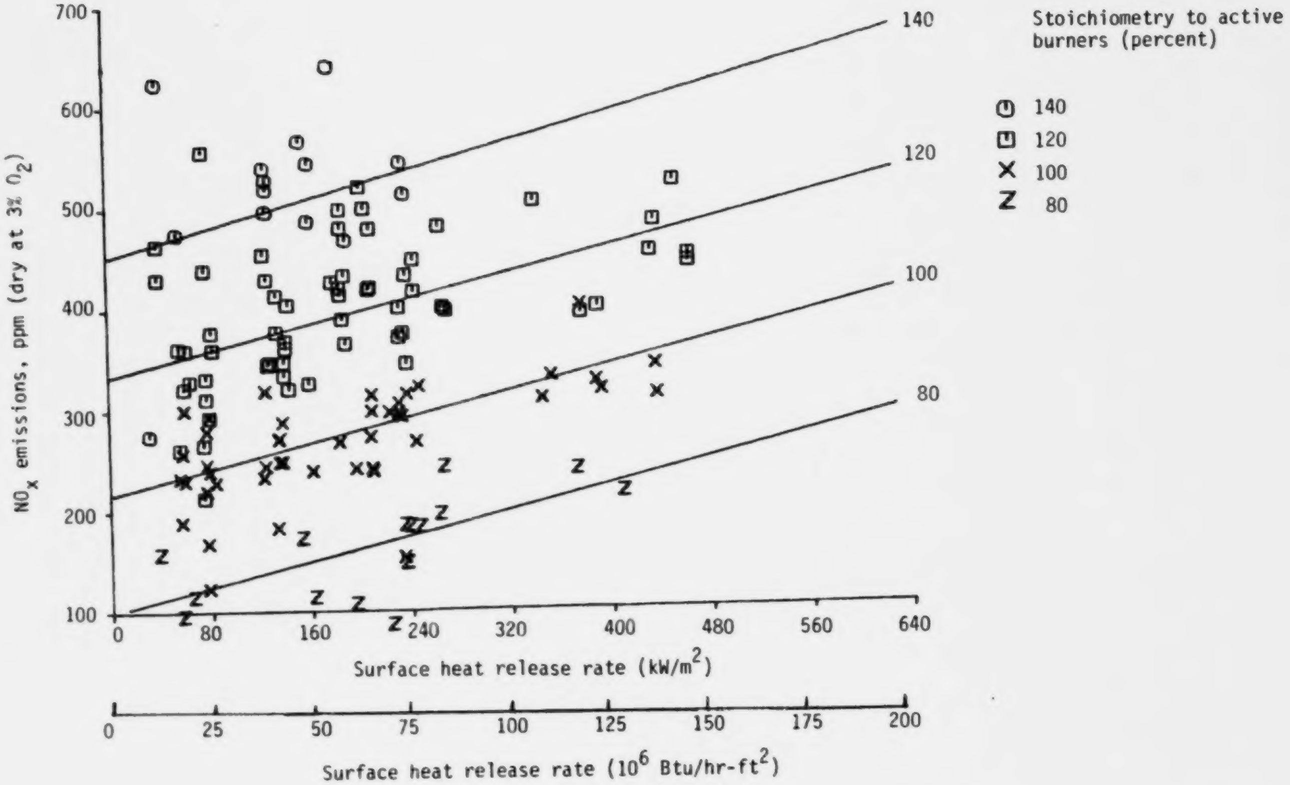

Figure 5-1. Effect of surface heat release rate and burner stoichiometry on NO_x from tangential coal-fired boilers.

Figure 5-2 shows another graphical representation of NO_x emissions variation with burner stoichiometry and heat input per active burner. The parametric curves were generated from the regression equation in a manner similar to that explained above for Figure 5-1. Again, the effect of decreasing NO_x with decreasing burner stoichiometry is clearly seen. Decreasing heat input per active burner, however, seems to have a mixed effect on NO_x. For burner stoichiometry above 120 percent, NO_x emissions decrease with reduced heat input, consistent with earlier discussion. Note that burner stoichiometries above 120 percent generally preclude OSC operation. For burner stoichiometries about 100 percent, the NO_x emissions sometimes actually decrease with increasing heat input per burner. This can be explained by noting that the data points for burner stoichiometries at about 100 percent or lower include tests with BOOS operation. In such cases, increasing heat input per active burner is tantamount to increasing the degree of off stoichiometry, as fuel flow to active burners must be increased under BOOS operation to maintain load. Under these circumstances the NO_x emissions should decrease with increasing heat input per burner, and that is precisely what is observed.

The above example points out the need to be very careful in interpreting the results of the regression analysis. The equations are valid only within the range of conditions of the original data base, sothat any generalizations should be made with caution. It should also be noted that the independent variables are often related to each other within certain ranges of operation. For example, LEA operation, without OSC, will influence both burner as well as furnace stoichiometry. Also, low load, without BOOS, will affect both the surface heat release rate and heat input per active burner. And, as pointed out earlier, BOOS operation will affect burner stoichiometry and heat input per active burner.

It is seen from the regression equation and from Figures 5-1 and 5-2 that the most effective operational technique for NO_x control on tangential coal-fired boilers seems to be reduction of burner stoichiometry. This can be accomplished to a certain extent with LEA and to a greater extent with OSC. Lower surface heat release rates also result in lower NO_x emissions. In addition, lower heat release per burner also tends to reduce NO_x emissions, at least when not operating under BOOS firing.

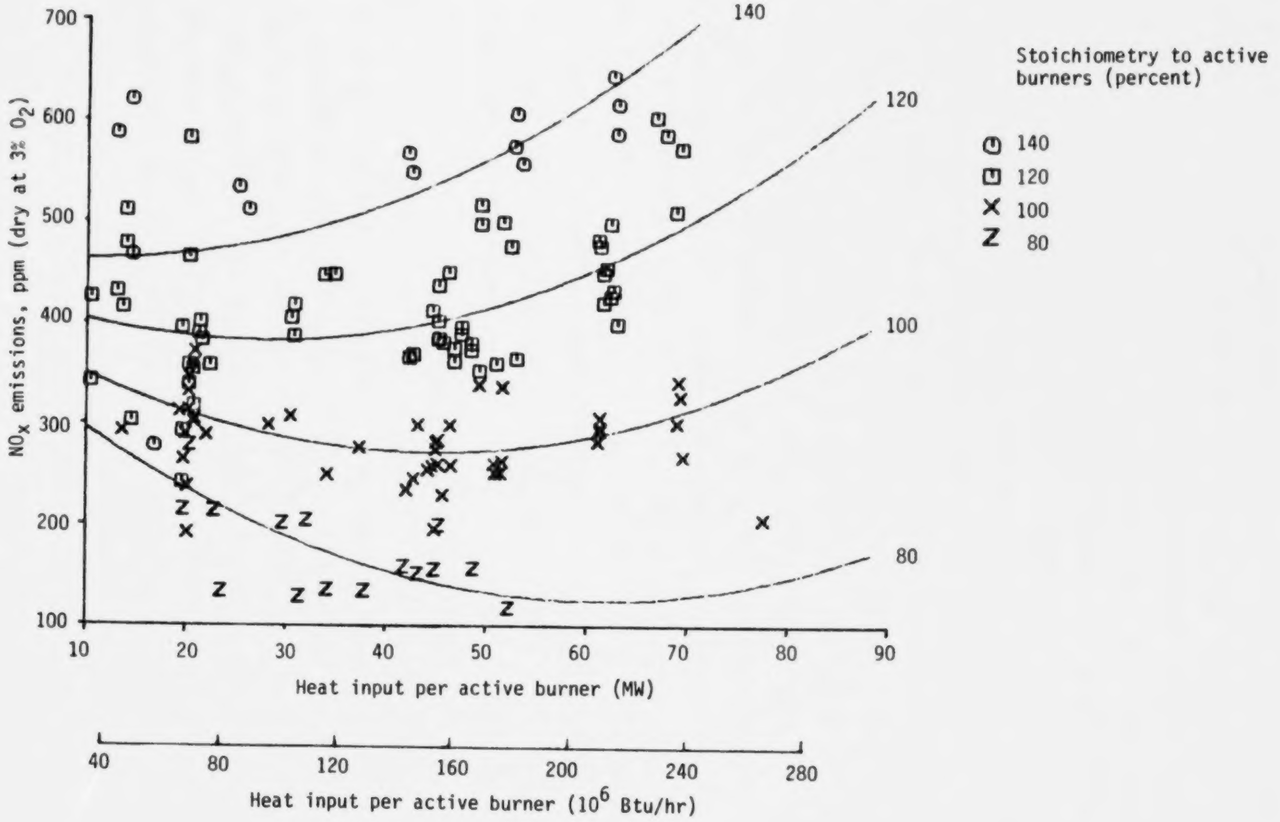

Figure 5-2. Effect of heat input and burner stoichiometry on NO$_x$ from tangential coal-fired boilers.

5.3.2 Horizontally Opposed Coal-Fired Boilers

The multiple regression analysis was also applied to horizontally opposed coal-fired boilers. Fifty-two tests on six boilers were selected for the analysis. The data included tests performed under baseline conditions as well as LEA, OSC, low load, and a combination of low load and OSC. In addition, data from a boiler tested with FGR were included. Some test data on a combination of low load and FGR, and OSC and FGR were also included.

The regression analysis yielded the following equation, which has a correlation coefficient of 0.91, i.e., 83 percent of the variance is explained by the expression:

$$y = -471 + 5.38(x_1) + 4.24 \times 10^{-6}(x_2) + 7.41(x_3)$$
$$-5.84(x_4) - 6.64 \times 10^{1}(x_5) + 2.46 \times 10^{1}(x_6)$$

where

y = NO_x emissions (ppm dry at 3 percent O_2)
x_1 = Stoichiometry to active burners (percent stoichiometric air)
x_2 = Heat input per active burner (W)
x_3 = Number of burners firing
x_4 = Flue gas recirculation (percent)
x_5 = Number of division walls
x_6 = Excess oxygen (percent)

The regression equation indicates that NO_x increases with increasing stoichiometry to burners, heat input to the burners, the number of burners firing, and overall excess oxygen, whereas NO_x decreases with increasing flue gas recirculation and number of division walls. These results are, in general, in agreement with past experience and theoretical considerations. Burner stoichiometry and overall excess air are known to have a large positive correlation with NO_x formation. Increased heat input to burners would also be expected to increase NO_x emissions. The positive correlation of a number of burners firing with NO_x probably stems from many factors. Larger boilers produce significant NO_x and usually have more burners. At partial loads NO_x generation is reduced and so are the number of active burners. Finally, with BOOS, the number of active burners decreases and so does NO_x. The number of division walls is negatively correlated with NO_x. This is most likely due to the increased surface area available for heat transfer with consequent lowering of flame temperatures.

The correlation of NO_x emissions with FGR is interesting and is shown in Figure 5-3 with burner stoichiometry as a parameter. Although the data are relatively sparse, the statistical correlation do point to a negative trend of NO_x emissions with increasing FGR. It should be noted also that the decrease in NO_x due to 20 percent FGR is approximately the same as the decrease in NO_x with a 10 percent reduction in excess air at the burners. FGR is known to inhibit thermal NO_x, whereas OSC controls both thermal and fuel NO_x. OSC is therefore expected to be a more effective NO_x control technique than FGR, in agreement with experience.

The effect of heat input per active burner on NO_x emissions is shown in Figure 5-4, again with burner stoichiometry as a parameter. The data scatter is rather large and very few data points are available for the substoichiometric region. Nevertheless, it is seen that, in general, increasing heat input per active burner increases NO_x. It also indicates the influence of burner stoichiometry on NO_x emissions. It should be reiterated here that the data base is limited, and that data from different manufacturers were incorporated together. Hence design differences between burners are masked in the correlations. Thus a large burner (high input) does not necessarily produce high NO_x. Indeed the new burners coming onstream today have designs that limit air/fuel mixing in the burner zone and hence limit NO_x production. In other words, burner design can overcome the tendency of higher NO_x with increasing heat input (Reference 5-24).

From the regression analysis, it can be seen that for horizontally opposed coal-fired boilers, reducing burner stoichiometry is a very effective means for controlling NO_x emissions. LEA reduces burner stoichiometry, but OSC must be employed if large reductions up to or below the stoichiometric level are desired. FGR also reduces NO_x but to a lesser extent than reduced burner stoichiometry. The implications for boiler design from this study are that increased cooling surface and decreased heat input per burner tend to decrease NO_x emissions. But as noted above, burner design, though not included in the correlation, is

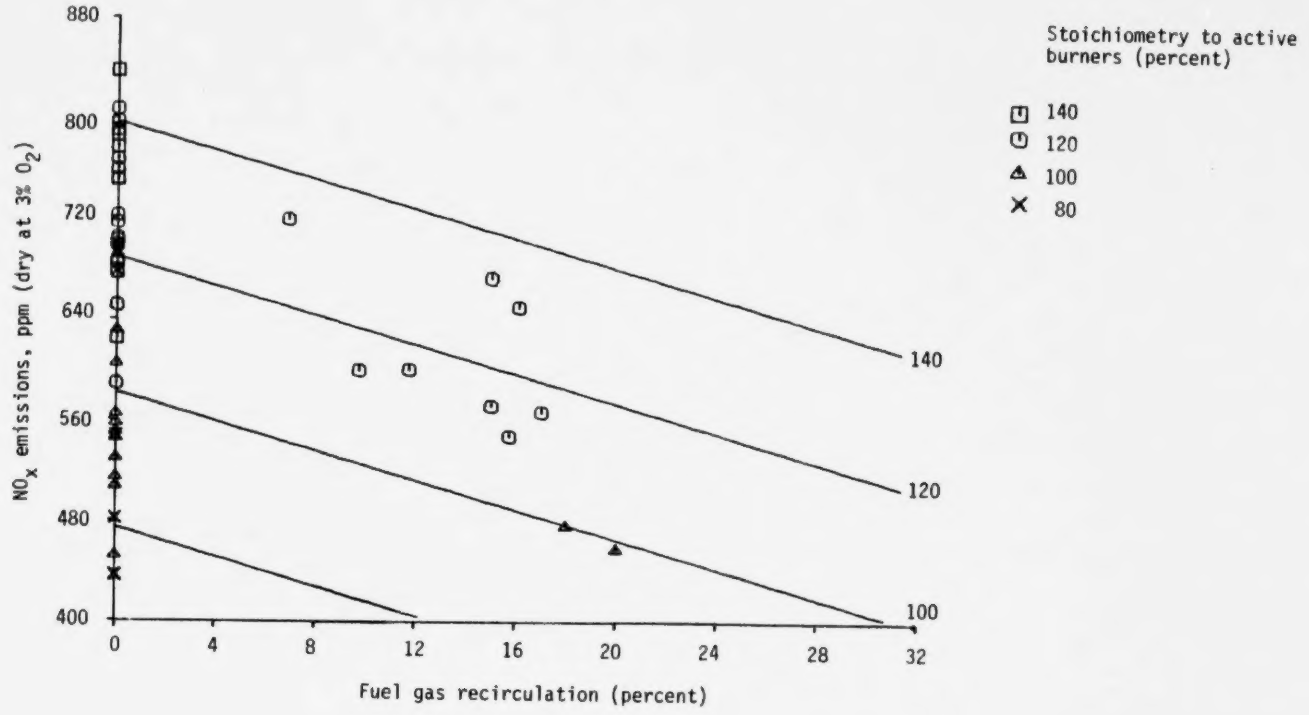

Figure 5-3. Effect of FGR and burner stoichiometry on NO$_x$ from horizontally opposed coal-fired boilers.

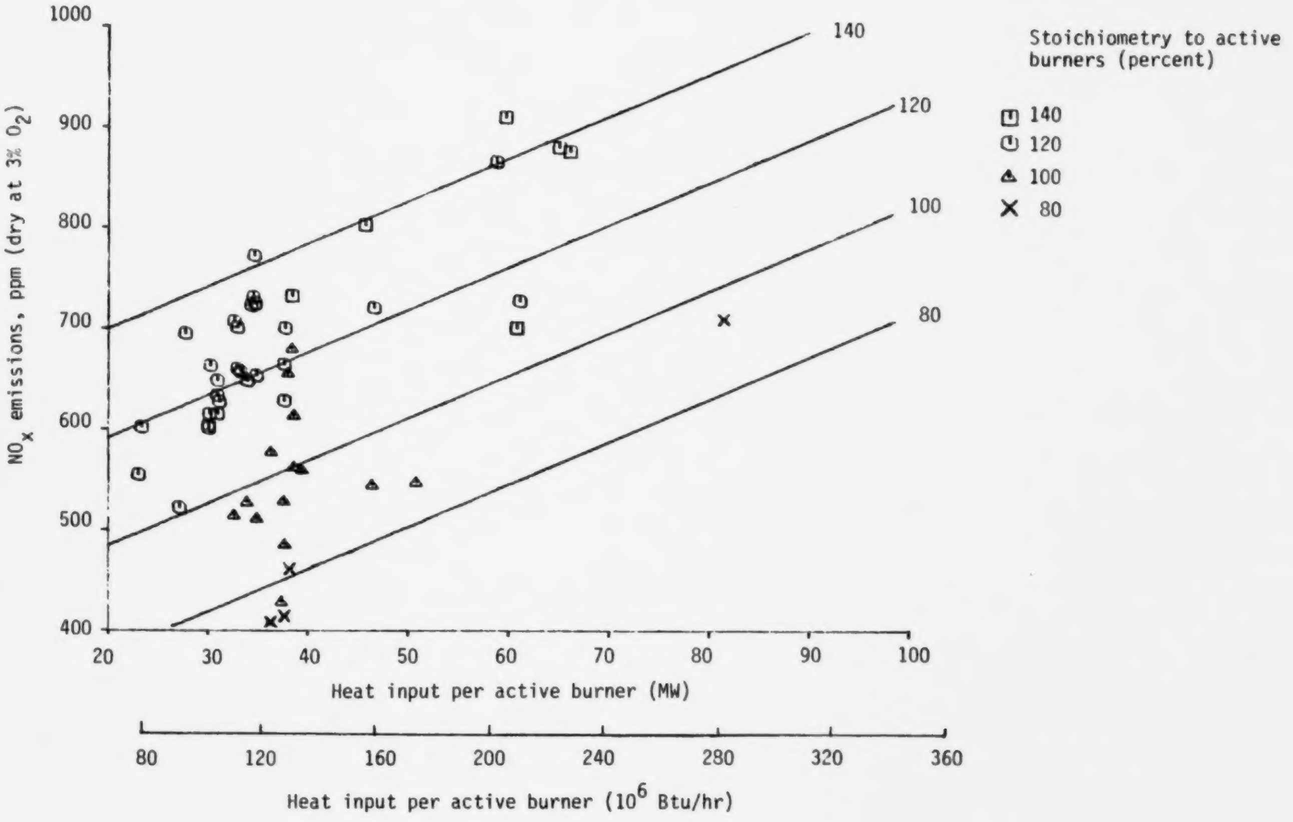

Figure 5-4. Effect of heat input and burner stoichiometry on NO_x from horizontally opposed coal-fired boilers.

equally if not more important than burner heat input. The regression model can be used to illustrate general trends in the change of NO_x emissions with design or operational changes. One should be very careful, however, not to extrapolate the equation beyond the range of data on which it was correlated.

5.3.3 Single Wall Coal-Fired Boilers

The multiple regression analysis was applied to single wall coal-fired boilers with data from 86 tests performed on eight boilers. The data included tests under baseline and low NO_x conditions. Low NO_x techniques included LEA, OSC, low load, and a combination of low load and OSC.

The regression analysis correlated the data with a correlation coefficient of 0.896, i.e., 80 percent of the variance was explained by the regression. The equation which best correlated the data was:

$$y = -140 + 1.98 \times 10^{-1}(x_3)(x_2) + 6.95 \times 10^{-5}(x_1)(x_5) + 4.5 \times 10^{-6}(x_1)(x_2)$$
$$+ 7.57 \times 10^{-8}(x_4)(x_2) - 1.02 \times 10^{-11}(x_1)(x_4)$$

where

y = NO_x emissions (ppm at 3 percent O_2)
x_1 = Surface heat release rate (W/m^2)
x_2 = Stoichiometry to active burners (percent stoichiometric air)
x_3 = Number of burners firing
x_4 = Heat input per active burner (W)
x_5 = Furnace excess oxygen (percent)

This regression equation is complex with many variables appearing several times in conjunction with other variables. The stoichiometry tothe active burners has a marked large positive correlation with NO_x emissions. The number of firing burners, the heat input per active burner, and the furnace excess oxygen are all also positively correlated with NO_x emissions. These positive correlations are consistent with theoretical considerations and past experience. Stoichiometry to active burners and overall excess oxygen have been shown to have a marked effect on thermal and fuel NO_x generation. The heat input per burner which is related to the flame intensity and, hence, peak temperatures should affect thermal NO_x emissions. The number of firing burners increases with boiler size, high load, and absence of BOOS firing, all of which tend to increase NO_x emissions. The effect of surface heat release rate is not straightforward and is discussed further below.

Figure 5-5 is a plot of NO_x emissions versus surface heat release rate with burner stoichiometry as a parameter. Here the trends are consistent with expectations based on previous correlations. NO_x emissions tend to increase with increasing surface heat release rate and burner stoichiometry. Figure 5-6 shows the variation of NO_x emissions with heat input to active burners and burner stoichiometry. Again the trends are consistent with expectations. NO_x emissions tend to increase with increasing heat release per burner and increasing stoichiometry. The data are sparse for higher heat release rates, so that predictions at those values may not be very accurate. Nevertheless, the trends should be correctly predicted.

From the regression analysis, it is seen that burner stoichiometry again has the greatest effect on NO_x emissions from single wall coal-fired boilers. LEA can be employed to decrease burner stoichiometry to a certain extent. OSC should be employed if further reduction is desired. Implications for boiler design are that decreasing heat input per burner can reduce NO_x emissions. But, as discussed in Section 5.3.2, burner design, a variable not incorporated here because of data limitations, can predominate over heat input. Finally decreasing heat release rate, all other factors equal, generally does reduce NO_x. The regression equation can be used to estimate trends in NO_x emissions due to design or operational changes. However, as most of the data on which the correlation is based are confined to a small range, care should be exercised when making numerical predictions.

5.3.4 Horizontally Opposed Oil-Fired Boilers

The data base for the multiple regression analysis on horizontally opposed, residual oil-fired units was relatively good. The total of 56 test points from the seven boilers tested gave more than 1 test point for each control and combination of control methods considered. The tests included baseline, low excess air, off stoichiometric combustion, flue gas recirculation, load reduction, and combinations of these control methods.

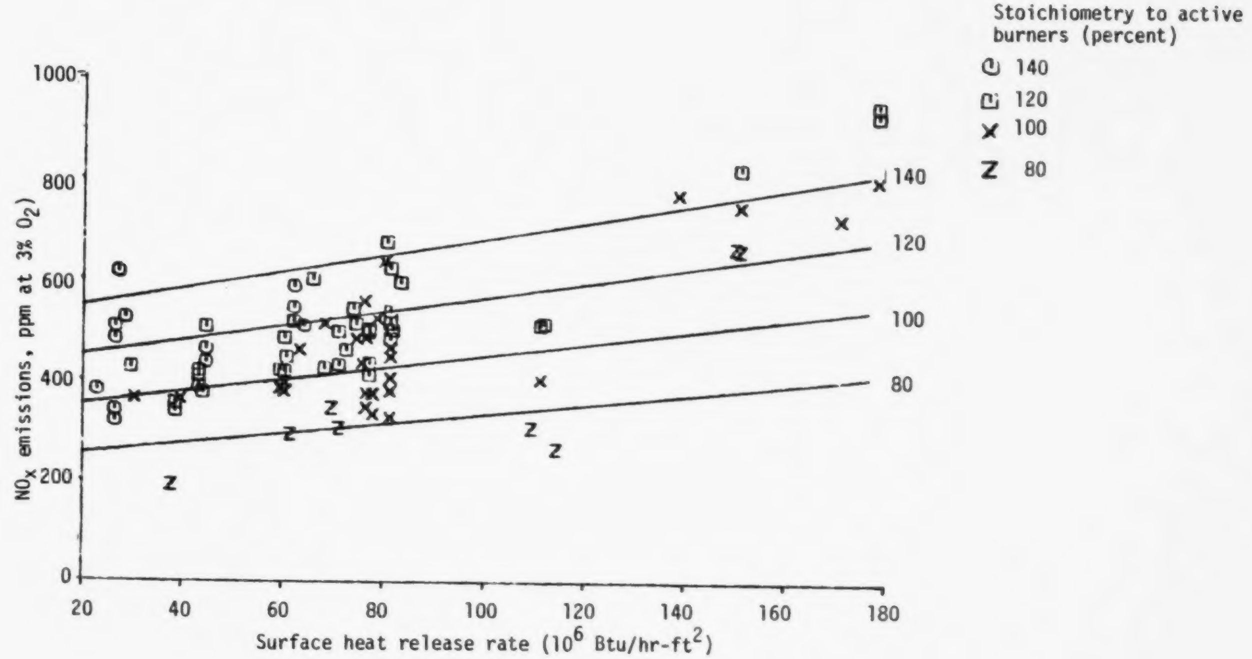

Figure 5-5. Effect of surface heat release rate and burner stoichiometry on NO_x from single wall coal-fired boilers.

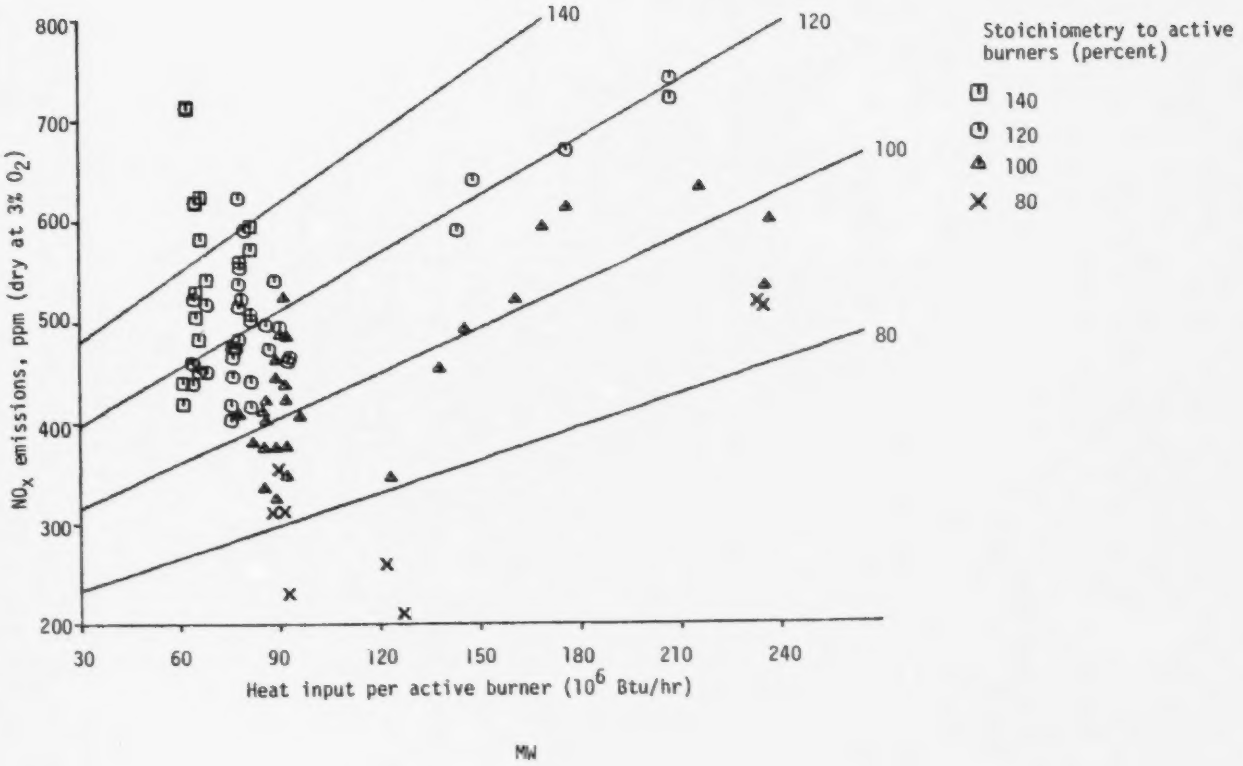

Figure 5-6. Effect of heat input per active burner and burner stiochiometry on NO_x from single wall coal-fired boilers.

The correlation explained variations in NO_x emissions to within 80 percent. The significant parameters were found to be firing rate, number of burners firing, stoichiometry to active burners, number of division walls,and furnace stoichiometry. The second order multiple regression equation which best correlated the data, with a correlation coefficient of 0.90 was:

$$y = -228 + 1.05 \times 10^{-1} (x_1)(x_2) + 7.23 \times 10^{-3}(x_3)^2 - 1.30 (x_1)(x_4) + 2.392(x_5)$$

where

y = NO_x emissions (ppm dry at 3 percent O_2)
x_1 = Firing rate (percent)
x_2 = Number of burners firing
x_3 = Stoichiometry to active burners (percent stoichiometric air)
x_4 = Number of division walls plus one
x_5 = Furnace stoichiometry (percent stoichiometric air)

The variable dependencies were not unexpected. Reducing the firing rate lowers the volumetric heat release rate. Thus, reduced heat release rate will lower the bulk gas temperature in the furnace resulting in reduced thermal NO_x formation. An increase in the number of active burners for a given heat release rate should also increase NO_x emissions, as more active burners firing will result in more thorough mixing of fuel and air in the peak flame temperature regions. The stoichiometry to active burners and the overall furnace stoichiometry influence NO_x formation in that higher oxygen concentrations in the peak flame temperature regions will increase NO_x formation. As shown in Figure 5-7, increasing either boiler load or burner stoichiometry increases NO_x emissions. Also, as shown in Figure 5-8, increasing either the number of burners firing or the burner stoichiometry increases NO_x emissions. Finally, furnace division walls add heat transfer surface to the furnace. The increased surface will result in greater heat transfer from the furnace gases thus lowering the furnace bulk gas temperature. This will reduce thermal NO_x formation, and thereby lower NO_x emissions.

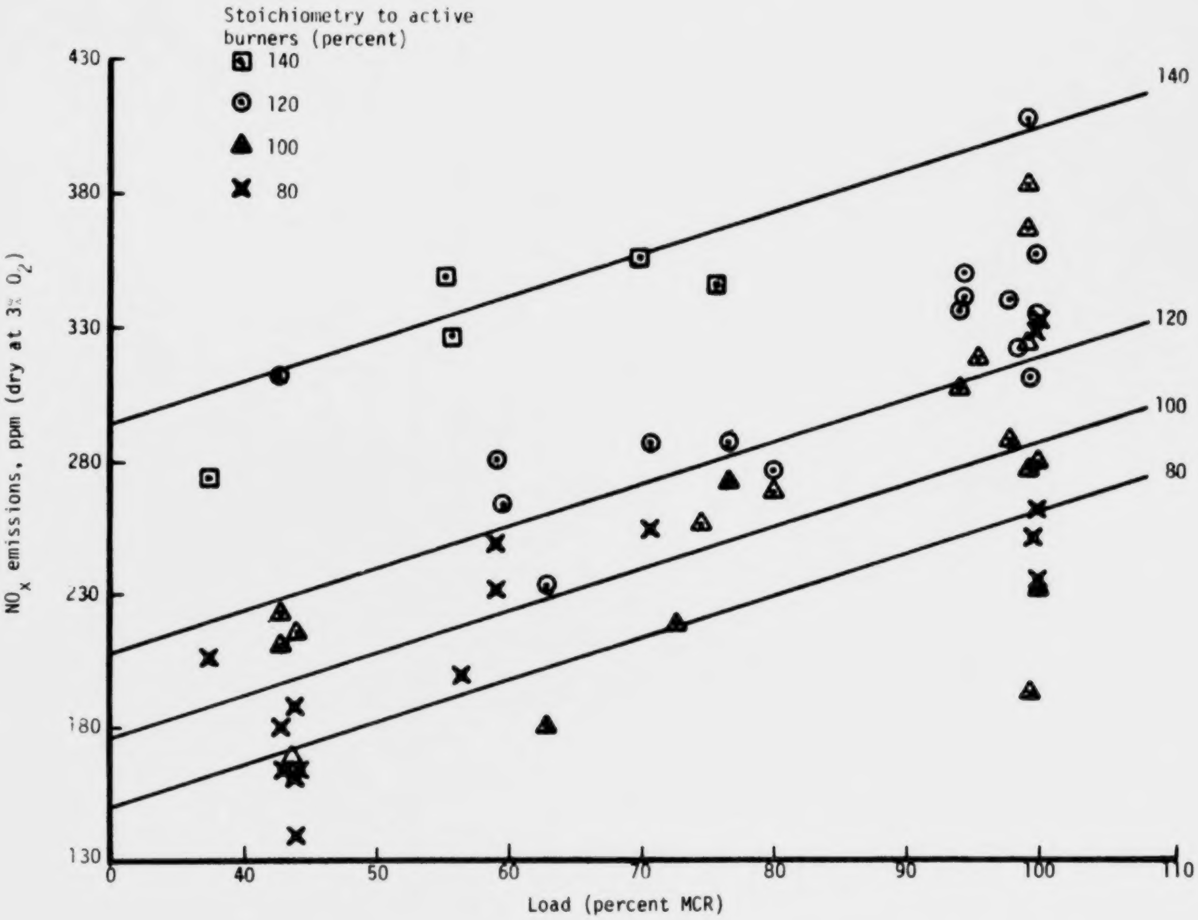

Figure 5-7. Effect of boiler load and burner stoichiometry on NO$_x$ from horizontally opposed oil-fired boilers.

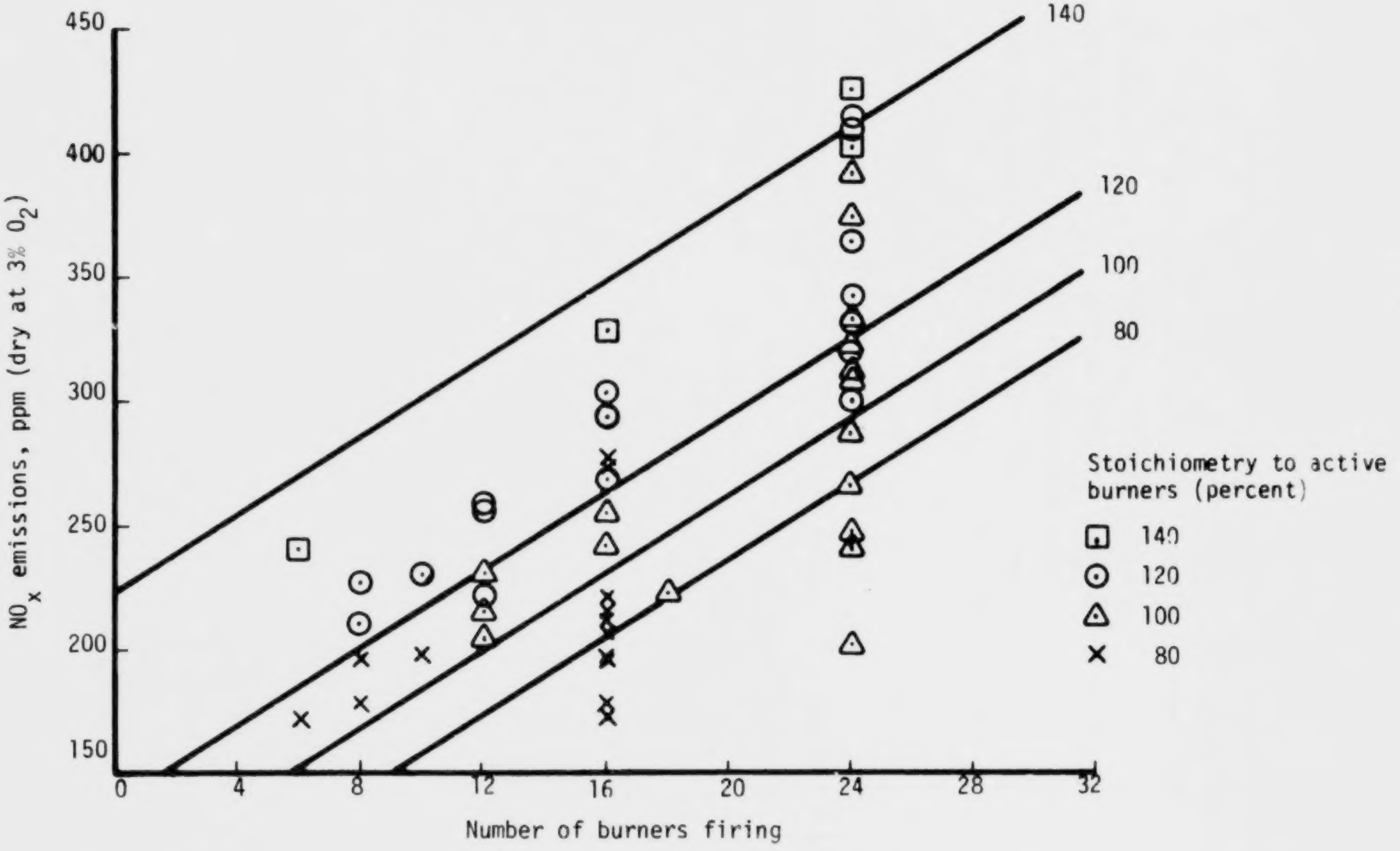

Figure 5-8. Effect of burner variables on NO$_x$ from horizontally opposed oil-fired boilers.

Expected effects of flue gas recirculation were not picked up in the correlation. One reason may be the limited data on the effect of FGR as a single NO_x control. Second, although more data were included on FGR in combination with other techniques, the effectiveness of FGR may be diminished when used in conjunction with other control methods.

5.3.5 Single Wall Oil-Fired Boilers

The data base for the multiple regression analysis for NO_x reduction in single wall oil-fired boilers consisted of 61 test points from seven boilers tested. This gave a minimum of four tests for each control and combination of control methods considered. The tests included baseline, low excess air, off stoichiometric combustion, flue gas recirculation, load reduction, and combinations of these control methods.

The correlation explained variations in NO_x emissions to within 68 percent. The significant parameters were found to be volumetric heat release rate, stoichiometry to active burners, the difference between furnace stoichiometry and burner stoichiometry, heat input to active burners, and number of burners out of service. The second order multiple regression equation best explaining the data, with a correlation coefficient of 0.83, was:

$$y = 173 + 2.28 \times 10^{-5} (x_1)(x_2) - 1.91 \times 10^{-3} (x_1) + 6.18 \times 10^{-8}(x_3)(x_4)$$

$$- 9.41 \times 10^{-7} (x_4)(x_5) + 3.60 \times 10^{-14} (x_4)^2$$

where

y = NO_x emissions (ppm dry at 3 percent O_2)
x_1 = Volumetric heat release rate (W/m^3)
x_2 = Stoichiometry to active burners (percent stoichiometric air)
x_3 = Furnace stoichiometry minus burner stoichiometry (percent)
x_4 = Heat input per active burner (W)
x_5 = Number of burners out of service

The importance of these parameters was expected. A reduction in the volumetric heat release rate lowers bulk gas temperature in the furnace. This results in reduced thermal NO_x formation. Figure 5-9 shows that for burner stoichiometries of 100 percent and greater an increase in NO_x is expected as the volumetric heat release rate

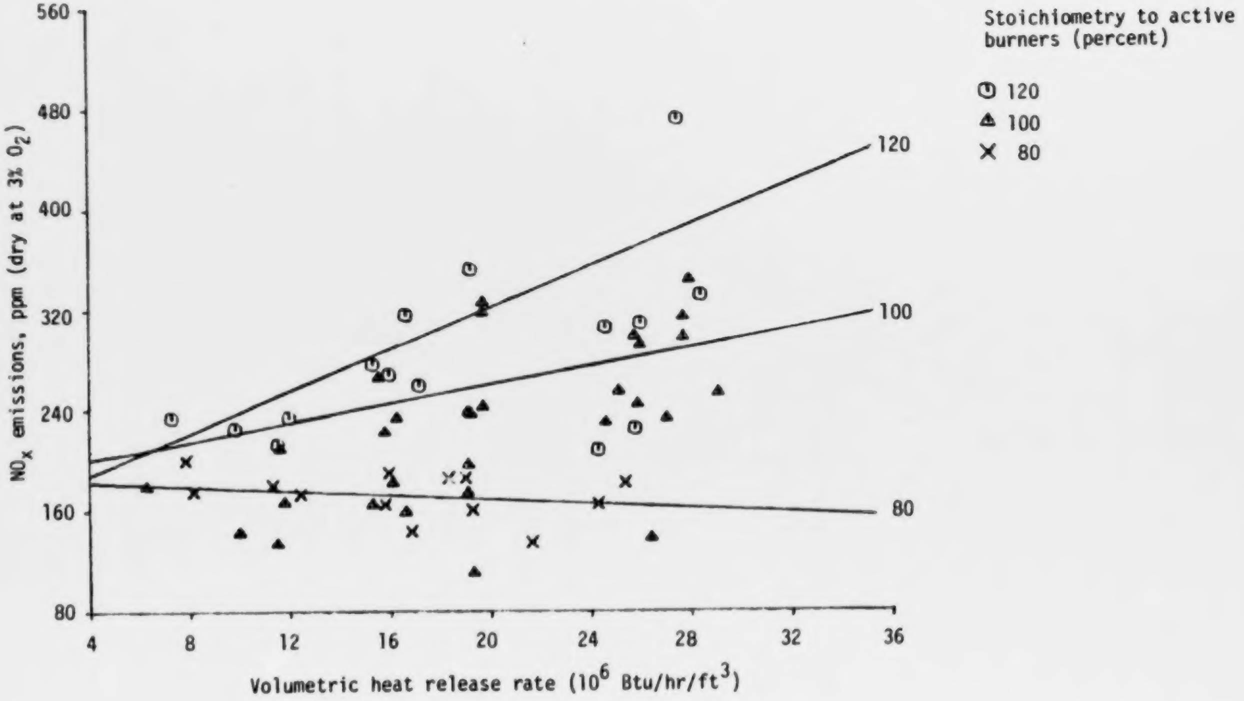

Figure 5-9. Effect of volumetric heat release rate and burner stoichiometry on NO$_x$ from single wall oil-fired boilers.

increases. For substoichiometric firing, the formation of NO_x is less sensitive to changes in volumetric heat release rates. In fact, for the 80 percent burner stoichiometry curve, a slight decrease in NO_x formation is observed when the volumetric heat release rate is increased, though this is expected to be only an artifact of the data. Stoichiometry to active burners is again important in this instance, as it has been for other firing type fuel combinations. Namely, a decrease in burner stoichiometry results in a decrease in the oxygen concentration in the peak flame temperature regions thus reducing NO_x formation.

The importance of the variable describing the difference between furnace and burner stoichiometry is a little misleading. A large difference could indicate a radical staging pattern which should greatly reduce NO_x formation. However, since there are practical restraints limiting the reduction of burner stoichiometry, a large difference between furnace and burner stoichiometry would more likely indicate a higher overall excess air level. Thus, an increase in this factor would lead to an increased level of NO_x formation.

The heat input per active burner factor appears in several terms. The net effect is that an increase in heat input per active burner results in an increase in NO_x formation. The heat input per active burner effect is tempered by a lower overall excess air level and by the number of burners out of service or the degree of staging. Obviously, for a given load, if a burner is taken out of service, the remaining active burners must increase their heat input. As shown in Figure 5-10, NO_x formation increases as the heat input per active burner increases but for most burner stoichiometries, this dependence is weaker than the volumetric heat release rate dependence.

Flue gas recirculation did not appear as a strong contributing factor in the NO_x predictions largely because of the scarcity of data on the effect of FGR as a single NO_x control. The effectiveness of FGR in NO_x control is diminished when used in conjunction with other control methods. Stoichiometry to the active burners is probably the most significant NO_x factor because the operator can regulate airflow to a certain extent without affecting unit operation.

5.3.6 Horizontally Opposed Gas-Fired Boilers

The data base for the regression analysis for NO_x reduction on horizontally opposed gas-fired boilers consisted of 74 tests on eight

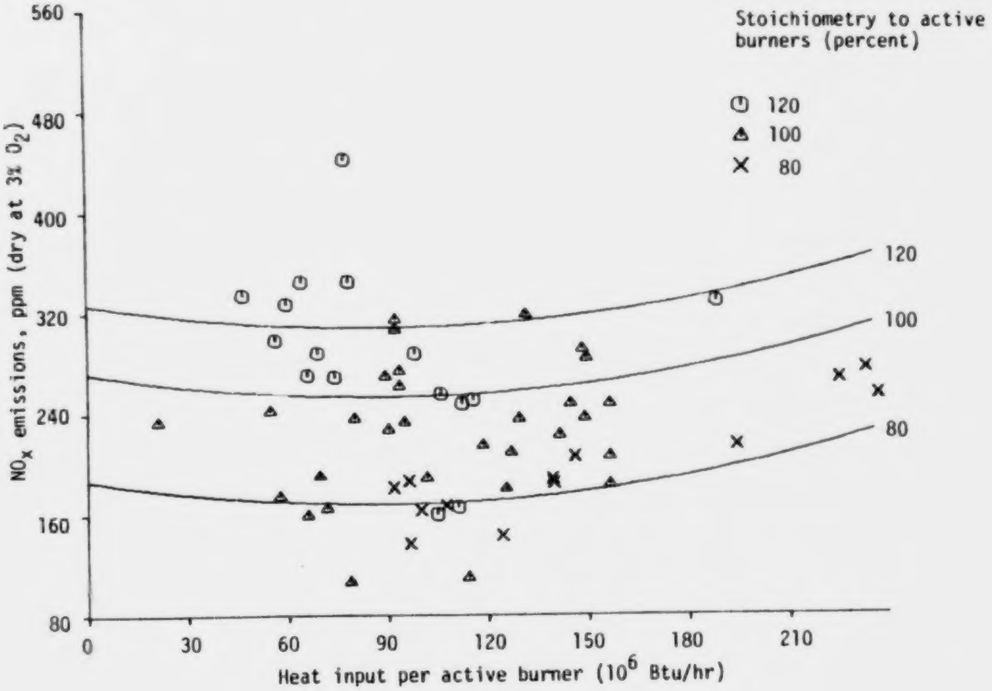

Figure 5-10. Effect of heat input and burner stoichiometry on NO$_x$ from single wall oil-fired boilers.

boilers. This gave a minimum of three tests for each control and combination of control methods considered except flue gas recirculation alone. The tests included baseline, low excess air, off stoichiometric combustion, load reduction, and combinations of these methods plus flue gas recirculation.

A logarithmic equation correlated the data more effectively than first or second order multiple regression schemes. The correlation equation explained variations in NO_x emissions to within 76 percent. The significant parameters were found to be firing rate, burner stoichiometry, furnace stoichiometry, number of division walls, and flue gas recirculation. The correlation equation best explaining the data, with a correlation coefficient of 0.87, was:

$$y = 4.42 \left[\left(x_1^{1.27}\right) \left(x_2^{2.5}\right) \left(x_3^{-0.267}\right) \left(x_4^{-0.267}\right) \left(x_5^{-0.035}\right) \right]$$

where

y = NO_x emissions (ppm dry at 3 percent O_2)
x_1 = Firing rate (percent)
x_2 = Stoichiometry to active burners (percent stoichiometric air)
x_3 = Furnace stoichiometry (percent stoichiometric air)
x_4 = Number of division walls plus one
x_5 = Flue gas recirculation rate plus 1 (percent)

Due to the logarithmic correlation equation, small changes in these factors result in large changes in predicted NO_x emissions.

The variation of NO_x emissions with firing rate was expected. Since thermal NO_x formation dominates exclusively in natural gas firing, any reduction in firing rate should reduce NO_x formation by reducing the bulk furnace gas temperature. Figure 5-11 shows that both burner firing rate and burner stoichiometry affect NO_x emissions significantly. However, since furnace stoichiometry should not vary greatly, the key factor will be burner stoichiometry. The effect of burner stoichiometry is clearly shown in Figure 5-11. This is expected since staged combustion is very effective for NO_x control with natural gas firing.

Flue gas recirculation entered the present correlation only weakly. However, as with the oil firing correlations discussed above, FGR data

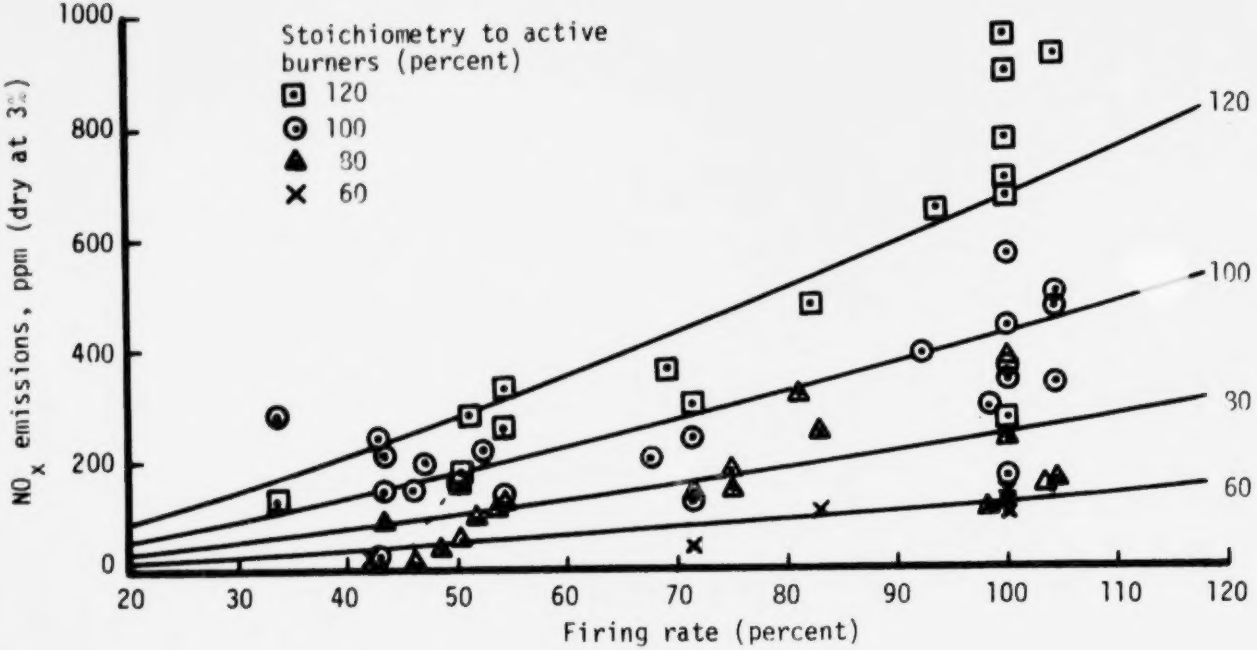

Figure 5-11. Effect of firing rate and burner stoichiometry on NO$_x$ from horizontally opposed gas-fired boilers.

were only available in combination with other controls. Thus, less credit was given FGR for NO_x reduction than if more data on FGR acting alone were available. Figure 5-12 shows that gas recirculation has much less effect on NO_x reduction than does burner stoichiometry. Aside from using reduced firing rates, the data show that the operator can control NO_x emissions most effectively by reducing burner stoichiometry.

5.3.7 Single Wall Gas-Fired Boilers

Forty-one tests from seven single wall gas-fired boilers were selected for use in the multiple regression analysis. The NO_x control techniques implemented in these tests were LEA, BOOS, FGR, load reduction, and combinations of these methods.

For single wall gas-fired boilers, the following equation correlates the data, with a correlation coefficient of 0.949; i.e., 90.2 percent of the variance in the data is explained by the regression:

$$y = -37.2 + 1.45 \times 10^{-5} (x_1)(x_2) - 1.85 \times 10^{-4} (x_1)(x_3)$$

$$+ 2.09 \times 10^{1} (x_3) - 6.46 \times 10^{-3} (x_2)(x_4)$$

where

y = NO_x emissions (ppm dry at 3 percent O_2)
x_1 = Surface heat release rate (W/m^2)
x_2 = Stoichiometry to active burners (percent stoichiometric air)
x_3 = Numbers of burners out of service
x_4 = Flue gas recirculation (percent)

As was found in the other boiler/fuel classifications treated, surface heat release rate and burner stoichiometry were the key parameters affecting NO_x formation in single wall gas-fired boilers. In gas-fired boilers, only thermal NO_x is formed and, as expected from basic combustion principles, lowering surface heat release rate and burner stoichiometry reduces this NO_x formation. This behavior is indicated in the regression equation and exhibited in Figure 5-13.

The second term of the regression equation, which has the product of the two key parameters, surface heat release and stoichiometry, is the dominant one. Number of burners out of service appears in the third term of the regression, and it is seen that implementing BOOS decreases NO_x as

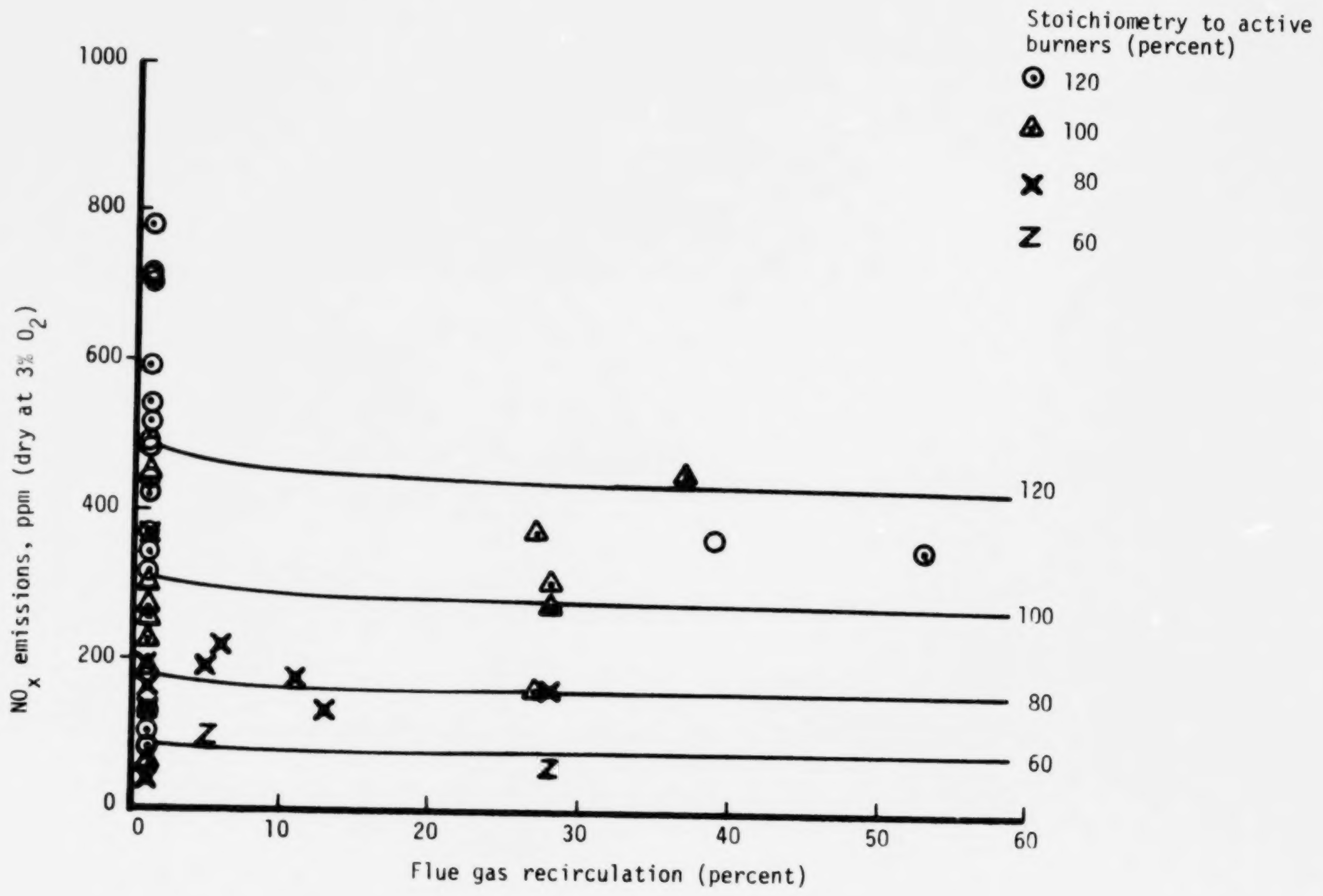

Figure 5-12. Effect of flue gas recirculation and burner stoichiometry on NO_x from horizontally opposed gas-fired boilers.

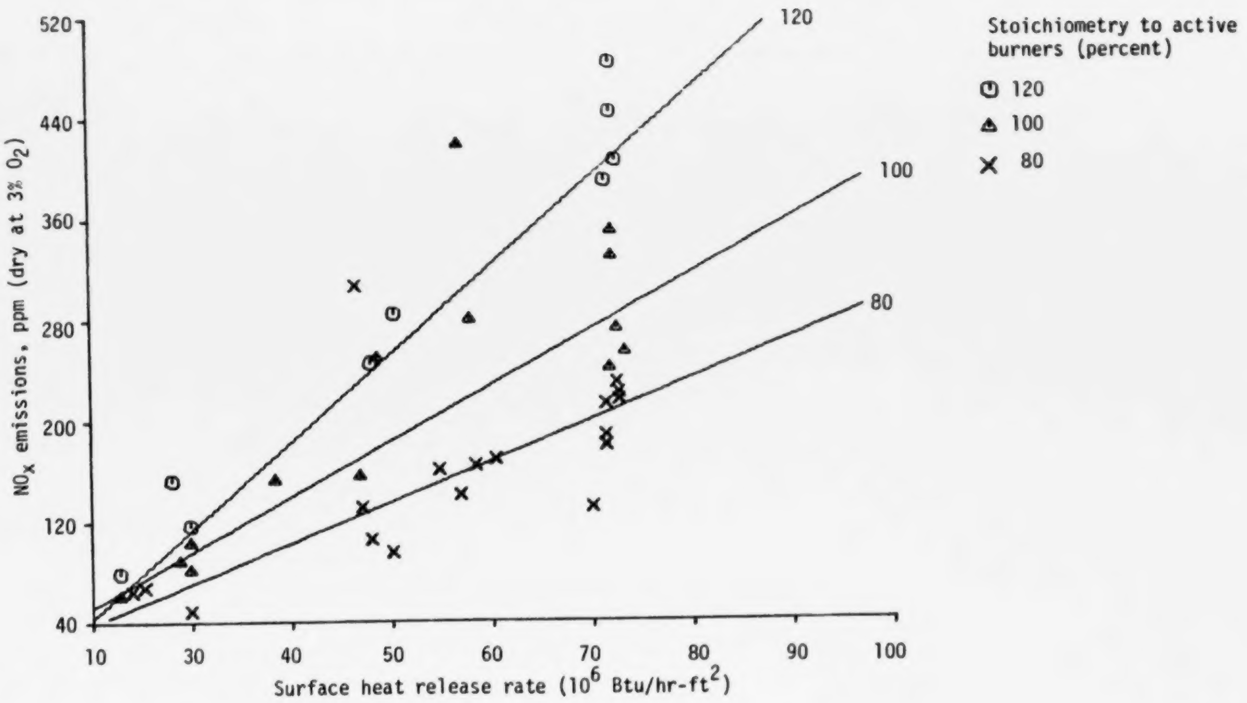

Figure 5-13. Effect of surface heat release rate and burner stoichiometry on NO_x from single wall gas-fired boilers.

expected. Surface heat release rate also appears in that third term. It should not be interpreted as implying that an increase in heat release decreases NO_x, because heat release appears in conjunction with BOOS. In other words, the regression suggests that BOOS produces a larger absolute magnitude drop in NO_x for a boiler with a higher heat release rate (with its expected higher baseline NO_x level). This points again to the dangers of examining the individual terms of the regression without considering the overall contribution of each variable to the entire correlation.

Finally, the last term indicates that flue gas recirculation does lower NO_x from single wall gas-fired boilers, as also shown in Figure 5-14. It is seen that combining FGR with BOOS (lower burner stoichiometry) is an effective NO_x control scheme.

In summary, it is seen that the two major variables affecting NO_x are surface heat release rate and burner stoichiometry. For an existing boiler, the former can be decreased by reducing load while the latter can be decreased by lowering excess air and implementing OSC (BOOS). This will result in lower NO_x. Obviously, it would have been best to have originally designed the boiler to operate with a lower surface heat release rate and fire off stoichiometrically, for example, via wider burner spacing and new burner design. For an existing boiler, this is not easily done, so to reduce NO_x load reduction, LEA, BOOS, and FGR can be implemented.

5.4 SUMMARY

A multiple regression model was used to correlate NO_x emissions with boiler/burner design and operating variables and fuel properties. The model explains the variation in NO_x on the average to within 20 percent for each boiler design/fuel classification. The key variables affecting NO_x formation were identified as:

- Heat input per active burner
- Stoichiometry to active burners
- Firing rate
- Number of burners firing (or degree of BOOS)
- Surface heat release rate
- Furnace stoichiometry
- Percent flue gas recirculation
- Number of furnace division walls

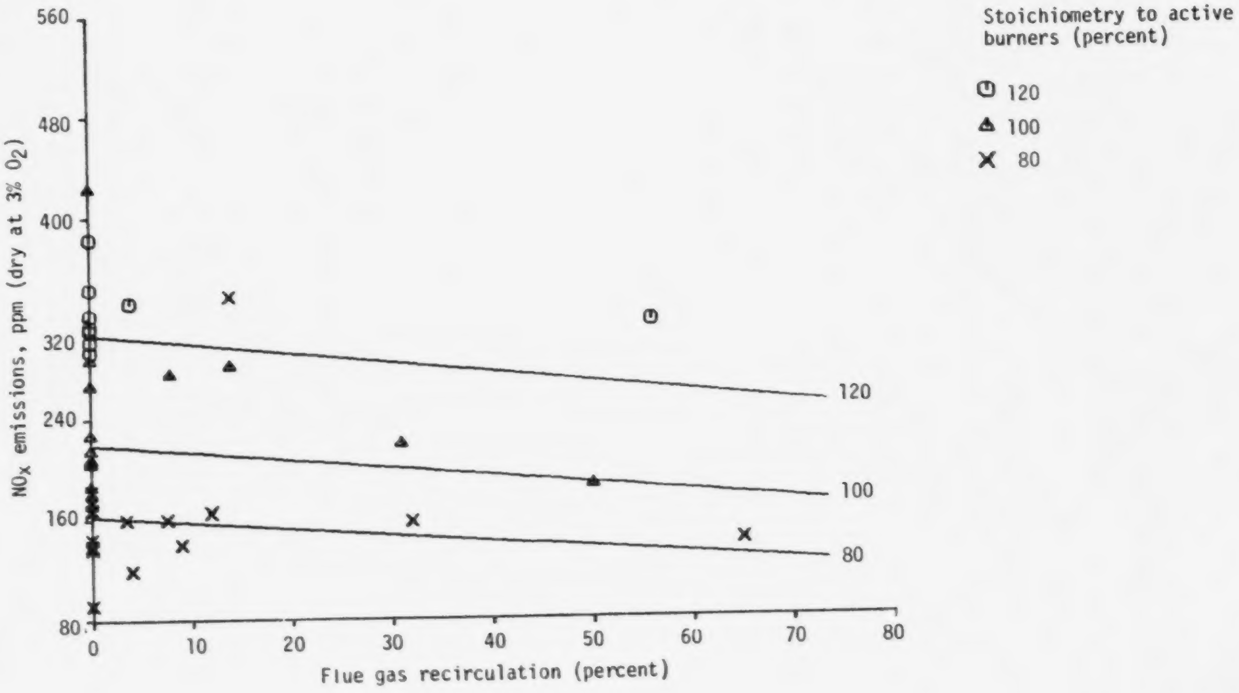

Figure 5-14. Effect of flue gas recirculation and burner stoichiometry on NO_x from single wall gas-fired boilers.

The only fuel property statistically adequate for use was the fuel type: coal, oil, or natural gas.

Thus, the correlation model served a very useful purpose in identifying key variables that affect NO_x formation and highlighting general trends. As an interpolative model, the correlation can be considered good considering the high correlation coefficients achieved with a large data base -- multiple tests on many different boilers under a diversity of test programs and procedures.

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SECTION 6

NO_x CONTROL CHARACTERIZATION: PROCESS ANALYSIS

To provide a meaningful evaluation of combustion modification NO_x controls, not only must their NO_x reduction capabilities be determined but also their impacts on boiler operation and maintenance, operating costs, and effluent emissions other than NO_x. Therefore, consistent process analysis procedures were developed, and applied to field test data, both published and unreported, from full-scale applications of controls. The approach adopted was to compare process variables that characterize the boiler system under baseline or normal operating conditions to those under controlled or low NO_x modes. Significant changes in the process variables were noted, and these were highlighted as real or potential problems and concerns.

To lay the foundation for the detailed analysis of controls, Section 6.1 summarizes the process analysis procedures and data sources employed. Sections 6.2 through 6.13 then analyze NO_x controls applied to major boiler design/fuel classifications as available process data on specific boiler tests permitted. A summary of the impact of NO_x controls on boiler operation and maintenance is then given in Section 6.14.

6.1 PROCESS ANALYSIS PROCEDURES

Process data collected during numerous utility boiler test programs were assembled for boilers operated under baseline and low NO_x conditions. A list of process variables investigated is given in Table 6-1. These data were then used to analyze changes in process variables due to low NO_x operation and thereby estimate the potential impact of such modes of firing on boiler operation and maintenance. Potential adverse effects were identified and evaluated. The more established combustion modification techniques for NO_x reduction were studied extensively along with some newer and/or less common NO_x control measures.

TABLE 6-1. PROCESS VARIABLES INVESTIGATED

Process Variables	Process Variables
Boiler Load Furnace Excess Air Excess Air at Firing Zone Percent Oxygen in Flue Gas Percent Oxygen in Windbox Furnace Cleanliness Condition Percent Overfire Air Percent Flue Gas Recirculation Burners Out of Service Damper Positions Burner Tilt Flowrates: Superheater Steam Reheater Steam Superheater Attemperator Spray Reheater Attemperator Spray Airflow Fuel Flow Pressures: Steam Drum Superheater Steam Outlet Reheater Steam Outlet Furnace Windbox Fan Inlet Fan Discharge Temperatures: Superheater Steam Reheater Steam Air Heater Air In/Out Air Heater Gas In/Out Furnace Gas Outlet Stack Gas Inlet Heat Absorption: Furnace Superheater Reheater Economizer	Fan Power Consumption Gas Emissions: NO_x SO_x Carbon Monoxide Hydrocarbons Polycyclic Organic Matter Particulate Loading Particulate Size Distribution Ringleman Smoke Density Carbon/Unburned Fuel Loss Additional Factors Considered: Corrosion Rates Slagging and Fouling Flame Instability Furnace Vibration Fan and Duct Vibrations

6.1.1 Assumptions

Boilers differ widely according to type of furnace and fuels fired. Accordingly, each boiler design/fuel classification was treated separately. Within each classification, however, there may still be large variations in variables which affect NO_x emissions. As noted earlier, in Section 5, design variables such as furnace volumetric and surface heat release rates can significantly affect baseline NO_x levels. The degree of NO_x control achievable and hence the needed changes in process variables to effect these emissions changes, therefore, may be substantially different between two boilers of the same type and firing similar fuels. For the purpose of the present study, however, it was assumed that these variations are small in comparison to the variations associated with furnace and fuel types. Moreover, it was assumed that the boilers for which data were available and analyzed in this study are representative of that type.

Data from a few well designed tests were available in which one or more operational variables were systematically varied to test their effect on NO_x emissions. Of course for precise treatment, secondary variables such as furnace conditions or fuel composition, must be maintained constant in order to isolate the effect of the variables being studied. This is often impossible when testing boilers under field conditions. In such cases, it was assumed that the effect of these secondary variables on NO_x emissions was small. Data were also available from some compliance tests. Such tests are usually much less systematically conducted, and the assumption that the secondary variables are maintained constant is much more tenuous. Still some insight can be gained from analyzing these cases.

6.1.2 Procedures

Process variable data were compiled for baseline and low NO_x modes of operation. The data were then analyzed and compared. Wherever possible, comparisons of baseline and controlled operation were made on tests which were similar in the general operating characteristics tested. Steam flow and load conditions, overall excess air levels, furnace conditions, etc., were matched as closely as possible. In addition, for tangential boilers, burner tilt and overfire air nozzle tilt were also matched for the baseline and controlled tests selected for comparison.

In certain tests, where the process data were sufficiently detailed, overall mass and energy balances were conducted. The mass balances were used to determine the amount of gaseous pollutants and particulate and solid matter emitted by the boiler under baseline and low NO_x conditions. Overall energy balances were used to check boiler efficiencies. Energy balances on individual boiler components established the distribution of heat absorption in the boiler. Attemperator spray flowrates were checked by heat and mass balances on superheater and reheater sections. Air and gas volume flowrates were calculated to determine the effect of changed operating conditions on fan draft and power requirements.

For coal-fired tests, data were collected on carbon loss in flyash, furnace slagging, and furnace wall tube corrosion. Corrosion may be a problem with coal-fired boilers due to the presence of sulfur and iron in the coal. When firing under reducing conditions, increased slagging combined with penetration of iron sulfide into the metal surfaces may increase tube wall corrosion rates. Most of the corrosion data were from tests conducted with corrosion coupons inserted in the furnace. Unfortunately, although tests of this type are quite useful in determining relative corrosion rates, they do not allow evaluating absolute wastage rates. Data were also obtained from some tests on coal- and oil-fired boilers on particle loading and size distribution. Some data were also available, mainly for oil and gas fuels, on flame instability, furnace vibrations, superheater tube temperatures and flame carryover to the convective section. Comparison of the process data were made for baseline and low NO_x modes of operation. Significant changes in the process variables were noted and evaluated for their impact on emissions and boiler operation and maintenance.

6.1.3 Data Sources

The boiler types investigated in this study were tangential, horizonally opposed, single wall and turbo furnaces. These four types encompass most of the fossil fuel fired utility boilers in service in the United States. The major NO_x control techniques analyzed in detail were off stoichiometric combustion (OSC) and flue gas recirculation (FGR). Off stoichiometric combustion includes firing with burners out of service (BOOS), biased burner firing (BBF) and overfire air (OFA) injection above the burner array. Off stoichiometric combustion was studied as applied to coal-, oil- and gas-fired boilers, whereas FGR to the windbox was treated in detail only in oil and gas fuels applications. In addition to these techniques various other methods on which sufficient process data were available were included in the study. Low excess air (LEA) firing was treated both as a NO_x control in this study and as a standard operating procedure. Low NO_x burners have been tested and are being installed in some boilers. Some data are also available on water injection (WI) and reduced air preheat (RAP), although they are not widely used as low NO_x techniques due to associated losses in boiler efficiency.

Table 6-2 gives a list of the boilers for which process data were available under low NO_x operation and which were used in this study. The sources of data are also listed in the table under the column marked References. All available published NO_x control test reports were reviewed for process data of sufficient detail for this investigation. In addition, several major boiler manufacturers and utility companies graciously supplied new or previously unpublished process data from their own test programs.

It should be noted that the omission of a NO_x control technique in Table 6-2 for a given boiler/fuel classification does not necessarily signify that that technique is not effective in controlling NO_x emissions. Some NO_x control measures had to be left out due to lack of adequate process data on those techniques for certain boiler/fuel classifications. The summary given in Section 6-14 attempts to fill in these gaps by giving a general survey of expected operational and maintenance impacts for all important NO_x control measures.

In the following sections, the major boiler/fuel classifications and applied controls, as discussed above, are analyzed as available data permitted.

6.2 TANGENTIAL COAL-FIRED BOILERS

Tangential coal-fired boilers have been perhaps the most studied boiler/fuel classification for potential NO_x control. Consequently, a substantial quantity of process data have been collected on these units operated under baseline and low NO_x conditions. The major low NO_x techniques tested have been LEA and OSC. Under OSC, both BOOS and OFA firing have been investigated. Very few adverse effects attributable to low NO_x operation have been reported in the numerous tests conducted. The major problem encountered was that of boiler derating associated with BOOS operation. Particulate loading also seemed to increase substantially in

TABLE 6-2. SUMMARY OF PROCESS DATA SOURCES

Furnace Type	Fuel	Boiler	Manufacturer	Utility Company	NO_x Control Technique	New or Retrofit	Reference
Tangential	Coal	Barry No. 2	CE	Alabama Power	BOOS, OFA	Retrofit	6-1
		Barry No. 4	CE	Alabama Power	LEA, BOOS	Retrofit	6-2
		Huntington Canyon No. 2	CE	Utah Power and Light	OFA	New, NSPS	6-3
		Columbia No. 1	CE	Wisconsin Power & Light	OFA	New, NSPS	6-3
		Navajo No. 2	CE	Salt River Project	LEA, BOOS, OFA	New, NSPS	6-4
		Comanche No. 1	CE	Public Service of Colorado	OFA	New	6-4
		Kingston No. 6	CE	Tennessee Valley Authority	LEA, BBF, BOOS	Retrofit	This report, Sec. 8.1
Opposed Wall	Coal	Harllee Branch No. 3	B&W	Georgia Power	LEA, BOOS	Retrofit	6-2
		Four Corners No. 4	B&W	Arizona Public Service	BOOS, WI	Retrofit	6-2
		Hatfield No. 3	B&W	Allegheny Power Service	BOOS, FGR	New	6-5
		E.C. Gaston No. 1	B&W	Southern Electric Generating	LNB, LEA, BOOS	Retrofit	6-4
		"B&W Units Nos. 1 & 2"[a]	B&W	--	LNB	New, NSPS	This report, App. A
		"FW Unit No. A"	FW	--	LEA, BOOS, LR		
Single Wall	Coal	Widows Creek No. 5	B&W	Tennessee Valley Authority	LEA, BOOS	Retrofit	6-6, 6-7
		Widows Creek No. 6	B&W	Tennessee Valley Authority	LEA, BOOS	Retrofit	6-2, 6-6
		Crist Station No. 6	FW	Gulf Power	LEA, BOOS	Retrofit	6-2
		Mercer No. 1	FW	Public Service Electric & Gas	LEA, BBF	Retrofit	6-7
		"FW Unit No. B"[a]	FW	--	LEA, BOOS, LR	Retrofit	This report. App. B
		"FW Unit No. C"[a]	FW	--	LEA, OFA, LR	New, NSPS	This report, App. B
Tangential	Oil	South Bay No. 4[a]	CE	San Diego Gas & Electric	LEA, BOOS, RAP	Retrofit	6-8
		Pittsburg No. 7	CE	Pacific Gas & Electric	OFA, FGR	Retrofit	6-9
		--	CE	Southern California Edison	FGR, BOOS	New	6-10, 6-12
Opposed Wall	Oil	Moss Landing Nos. 6 & 7[a]	B&W	Pacific Gas & Electric	OFA, FGR	Retrofit	6-9, 6-11
		Ormond Beach Nos. 1 & 2	FW	Southern California Edison	FGR, OFA, BOOS, WI	OFA New FGR Retrofit	6-10, 6-12
		--	B&W	Southern California Edison	FGR, OFA, BOOS	OFA New FGR Retrofit	6-10
		Sewaren Station No. 5	B&W	Public Service Electric & GAs	LEA, BOOS	Retrofit	6-7
		"FW Unit No. D"[a]	FW	--	LEA, OFA, BOOS, FGR	OFA New BOOS, FGR Retrofit	This report, App. B

[a] Denotes new results or previously unreported data.

TABLE 6-2. Concluded

Furnace Type	Fuel	Boiler	Manufacturer	Utility Company	NO$_x$ Control Technique	New or Retrofit	Reference
Single Wall	Oil	Encina Nos. 1, 2 & 3[a]	B&W	San Diego Gas & Electric	LEA, BOOS	Retrofit	6-13
Turbo Furnace	Oil	South Bay No. 3[a]	RS	San Diego Gas & Electric	Air adjustment WI, RAP	Retrofit	6-8
		Potrero No. 3-1	RS	Pacific Gas & Electric	OFA, FGR	Retrofit	6-9
Tangential	Gas	South Bay No. 4[a] Pittsburg No. 7	CE CE	San Diego Gas & Electric Pacific Gas & Electric	LEA, BOOS OFA, FGR	Retrofit Retrofit	6-8 6-9
Opposed Wall	Gas	Moss Landing Nos. 6 & 7[a] Pittsburg Nos. 5 & 6 Contra Costa Nos. 9 & 10	B&W B&W B&W	Pacific Gas & Electric Pacific Gas & Electric Pacific Gas & Electric	OFA, FGR OFA, FGR OFA, FGR	Retrofit Retrofit Retrofit	6-9, 6-11, 6-14 6-9 6-9
Single Wall	Gas	Encina Nos. 1, 2 & 3[a]	B&W	San Diego Gas & Electric	BOOS	Retrofit	6-13
Turbo Furnace	Gas	South Bay No. 3[a]	RS	San Diego Gas & Electric	Air adjustment WI, RAP	Retrofit	6-8
		Potrero No. 3-1	RS	Pacific Gas & Electric	OFA, FGR	Retrofit	6-9

[a] Denotes new results or previously unreported data.

certain units under OSC. However, other important process variables such as efficiency, corrosion, carbon losses, particulate size distribution, and heat absorption profiles remained either unaffected or changed only by small amounts under low NO_x operation. A detailed discussion on the results of various tests is given below. The results are summarized at the end of the subsection.

Details of extensive tests carried out on three tangential coal-fired units by Combustion Engineering, Inc., are given in References 6-1 and 6-3. The three boilers tested were: Barry No. 2, a 125 MW unit operated by Alabama Power Company; Columbia No. 1, a 525 MW unit operated by Wisconsin Power and Light Company; and Huntington Canyon No. 2, a 430 MW unit operated by Utah Power and Light Company. The Barry boiler is an older unit which was retrofitted with OFA ports during the course of testing. The other two are new NSPS units with factory-equipped OFA ports. The types of coal fired were Eastern bituminous, Western sub-bituminous and Western bituminous for Barry, Columbia and Huntington, respectively. A comparison of process variables under baseline is shown in Tables 6-3, 6-4, and 6-5 for the three boilers.

From the tables, it is seen that OSC was quite effective in controlling NO_x emissions from all three boilers. Of course, the range in NO_x reduction varied from boiler-to-boiler and from test-to-test due to variations in baseline excess air levels, amount of reduction in burner stoichiometry, and differences in boilers and fuels fired. However, on the average, for all three boilers, it was found that NO_x levels decreased by 40 to 55 ng/J (0.09 to 0.13 $lb/10^6$ Btu) for a 10 percent decrease in air to the burners.

The major impacts of NO_x controls occurred with BOOS firing on the Barry boiler where the unit was derated by approximately 20 percent as is shown in Table 6-3. In this boiler, derating occurred due to lack of spare coal pulverizer capacity. In general, boiler derating will occur in all coal-fired boilers without extra pulverizer capacity when operated under BOOS. From Table 6-3 it is also seen that in the Barry unit, gas temperature at the furnace outlet increased with OFA firing, as measured by special thermocouples installed to make these measurements. This was expected though, since OSC operation tends to lengthen the combustion zone so that, for the same load and burner tilt, completion of combustion occurs

TABLE 6-3. COMPARISON OF FLOW VARIABLES FOR A 125 MW TANGENTIAL EASTERN BITUMINOUS COAL-FIRED BOILER OPERATED UNDER SIMILAR CONDITIONS AT BASELINE AND LOW NO_x CONDITIONS (Reference 6-1)

Process Variables		Baseline	BOOS Operation	Significant Difference from Baseline for BOOS firing	OFA Operation	Significant Difference from Baseline for OFA firing
Test Condition		Full load	Maximum possible load		Full load	
Furnace Condition		Clean	Clean		Clean	
Load	MW	124	102	-18 %	125	
Main Steam Flow	kg/s (10^3 lb/h)	112.2 (890.7)	87.2 (692)	-22 %	115.6 (917)	
Furnace Excess Air	Percent	22.7	24.2		21.6	
Th. Air to Fuel Fir. Zone	Percent	117.9	94.7	-23.2	90.7	-27.2
Burner Tilt	Degrees	+3	-5		-4	
OFA Tilt	Degrees	-	-		0	
Boiler Efficiency	Percent	89.0	88.8		89.0	
NO_x[a]	ppm (0% O_2)	494	285	-42%	339	-31%
CO[a]	ppm (0% O_2)	31.2	26.6		26.1	
C loss in Flyash[a]	Percent	0.48	0.25	-48%	0.61	+27%
Dust Loading[a]	g/m^3 (10^{-3} lb/scf)	4.2 (0.262)	8.6 (0.540)	+106%	8.58 (0.539)	+106%
SH Temp	K (°F)	812 (1002)	811 (0.011)		811 (1000)	
RH Temp	K (°F)	787 (957)	788 (959)		809 (997)	22K (40°F)
Steam Pressure	MPa (psi)	12.8 (1859)	12.7 (1845)		12.9 (1873)	
SH Attemp. Spray Flow	kg/s (10^3 lb/h)	1.1 (9.10)	2.0 (15.6)	+71%	4.94 (39.2)	+33%
RH Attemp. Spray Flow	kg/s (10^3 lb/h)	0.25 (2.0)	0.11 (0.9)	-55%	0	-100%
Furnace Outlet Temp	K (°F)	1499 (2239)	1468 (2183)	-31K (-56°F)	1560 (2350)	61K (+111°F)
Heat Absorption Profile						
Economizer	Percent of total	4.0	4.0		2.6	-35%
Furnace	Heat release	47.9	47.5		46.0	
Primary Superheater	Heat release	17.8	16.0	-10%	17.7	
Secondary Superheater	Heat release	8.1	9.8	+21%	9.8	+21%
Reheater	Heat release	11.1	11.4		12.8	+15%
Total Heat Absorbed	Heat release	89.0	88.8		89.0	
Losses	Heat release	11.0	11.2		11.0	

[a] At economizer outlet

TABLE 6-4. COMPARISONS OF PROCESS VARIABLES FOR A 525 MW TANGENTIAL WESTERN SUB-BITUMINOUS COAL-FIRED BOILER OPERATED UNDER SIMILAR CONDITIONS AT BASELINE AND LOW NO_x MODES (Reference 6-3)

Process Variables		Baseline	OFA Operation	Significant Difference
Test Conditions		Full Load	Full Load	
Furnace Conditions		Clean	Clean	
Load	MW	524	523	
Main Steam Flow	kg/s (10^6 lb/hr)	442 (3.51)	444 (3.52)	
Furnace Excess Air	Percent	21.8	26.9	Significant
Th. Air to Fuel Fir. Zone	Percent	118.9	106.0	-12.9
Burner Tilt	Degrees	+1	-5	
OFA Tilt	Degrees	0	0	
Boiler Efficiency	Percent	87.5	87.3	
NO_x[a]	ppm (0% O_2)	520	389	-25%
CO[a]	ppm (0% O_2)	16	10	
C loss in Flyash[a]	Percent	0.03	0.02	
SH Temp	K (°F)	813 (1004)	817 (1011)	
RH Temp	K (°F)	815 (1008)	819 (1015)	
SH Attemp. Spray Flow	kg/s (10^3 lb/hr)	11.0 (87.3)	19.0 (150.8)	+73%
RH Attemp. Spray Flow	kg/s (10^3 lb/hr)	12.0 (95.2)	8.0 (63.5)	-33%
Steam Pressure	MPa (psi)	16.88 (2448)	16.95 (2458)	
FD Fan	Amps	401	434	+8%
ID Fan	Amps	920	1000	+9%
Heat Absorption	Percent of Total			
Economizer	Heat Release	14.4	15.7	
Furnace	Heat Release	27.3	25.2	
Primary Superheater	Heat Release	17.2	17.0	
Secondary Superheater	Heat Release	11.2	13.2	
Reheater	Heat Release	17.2	16.3	
Total Heat Absorbed	Heat Release	87.5	87.3	
Losses	Heat Release	12.5	12.7	

[a] At economizer outlet

TABLE 6-5. COMPARISON OF PROCESS VARIABLES FOR A 430 MW TANGENTIAL WESTERN BITUMINOUS COAL-FIRED BOILER OPERATED UNDER SIMILAR CONDITIONS AND LOW NO$_x$ CONDITIONS (Reference 6-3)

Process Variables		Baseline	OFA Operation	Significant Difference
Test Conditions		Max Load	Max Load	
Furnace Condition		Mod Dirty Furnace	Mod Dirty Furnace	
Load	MW	433	428	
Main Steam Flow	kg/s (10^6 lb/hr)	375 (2.98)	370 (2.94)	
Furnace Excess Air	Percent	20.2	19.2	
Th. Air to Fuel Fir. Zone	Percent	118.1	96.6	-12.5
Burner Tilt	Degrees	+8	+10	
OFA Tilt	Degrees	0	0	
Boiler Efficiency	Percent	90.34	90.46	
NO$_x^a$	ppm (0% O$_2$)	514	446	-13%
CO^a	ppm (0% O$_2$)	20	162	+138 ppm
C loss in Flyash^a	Percent	0.50	0.24	-52%
SH Temp	K (°F)	809 (997)	804 (998)	
RH Temp	K (°F)	811 (1000)	816 (1009)	
Steam Pressure	MPa (psi)	17.24 (2500)	16.99 (2464)	
SH Attemp. Spray Flow	kg/s (10^3 lb/hr)	0	0	
RH Attemp. Spray Flow	kg/s (10^3 lb/hr)	6.0 (47.6)	1.0 (7.9)	-83%
FD Fan	Amps	434	433	
ID Fan	Amps	772	774	
Heat Absorption Profile	Percent of Total			
Economizer	Heat Release	16.6	14.8	-11%
Furnace	Heat Release	28.5	31.2	+9%
Primary Superheater	Heat Release	12.9	13.8	
Secondary Superheater	Heat Release	16.4	15.4	
Reheater	Heat Release	15.8	15.4	
Total Heat Absorbed	Heat Release	90.3	90.5	
Losses	Heat Release	9.7	9.5	

[a] At economizer outlet

higher in the furnace. The furnace outlet gas temperature, therefore, rises and the heat transfer to the convective section is correspondingly affected. In Table 6-3, it is seen that the superheater attemperator spray flowrate is approximately quadrupled on OFA firing at Barry. This is, however, atypical. Table 6-4 shows that at Columbia the increase in spray flow was 73 percent under OFA, and Table 6-5 indicates no attemperation was necessary under OFA at Huntington. Even at Barry and Columbia, where increased attemperation was required, the spray flow never exceeded 5 percent of the main steam flow, which is well within acceptable design limits. There was, therefore, no danger of attemperator capacities being exceeded which would have caused serious problems and resulted in boiler derating. Moreover, in all three boilers, the reheater spray attemperator flowrates did not increase with OSC operation; thus, there was no adverse effect on cycle efficiencies.

The changed gas temperature profile due to OSC may be expected to change the heat absorption profile in the boiler. In extreme cases, this could necessitate hardware changes such as removal of superheater and reheater surface and perhaps addition of economizer surface to make up the difference. The heat absorbed in the various components of the boiler is given in Tables 6-3, 6-4, and 6-5 and is depicted graphically in Figures 6-1, 6-2, and 6-3 for the Barry, Columbia and Huntington units, respectively. It is seen that changes in the heat absorption profile were only minor.

To show the effect of OSC operation on other emissions, an overall mass balance is given in Figure 6-4 for the Barry No. 2 unit. The sulfur dioxide emissions varied only slightly, mostly due to the variation in sulfur content of the coals fired. Carbon monoxide emissions were also mostly unaffected. Carbon monoxide generation usually increased sharply once the burner stoichiometry or overall excess air level dropped below a certain limit. Boiler operating conditions under OSC should therefore be set so as to always operate above this limit. The particulate carryover at the economizer outlet also increased substantially both under BOOS and OFA operation. Results of tests on other boilers (as discussed in subsequent sections) show mixed results of the effects of low NO_x operation on particulate emissions. Nevertheless, the possibility of increased particulate emissions remains a source of concern.

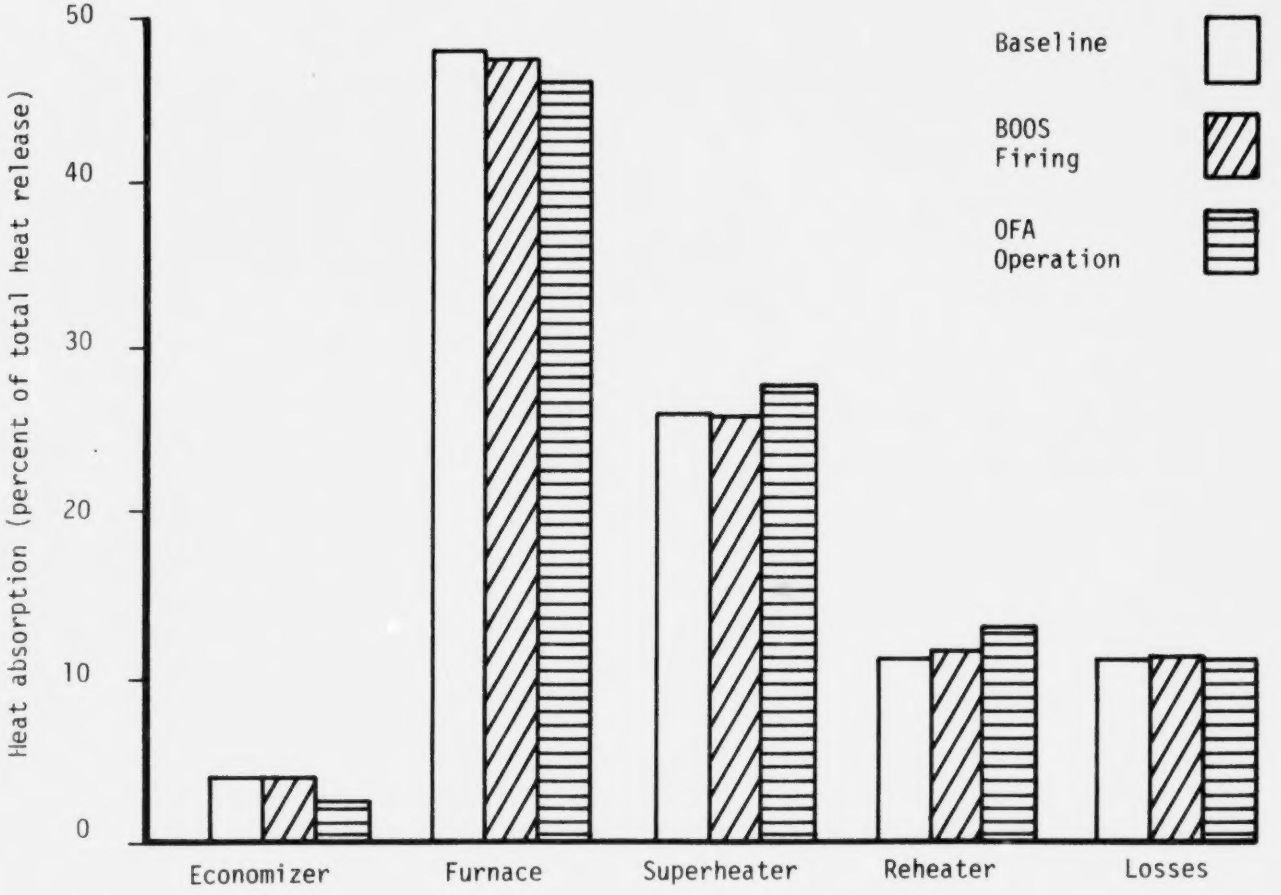


Figure 6-1. Heat absorption profile for Barry Unit No. 2 (Reference 6-1).

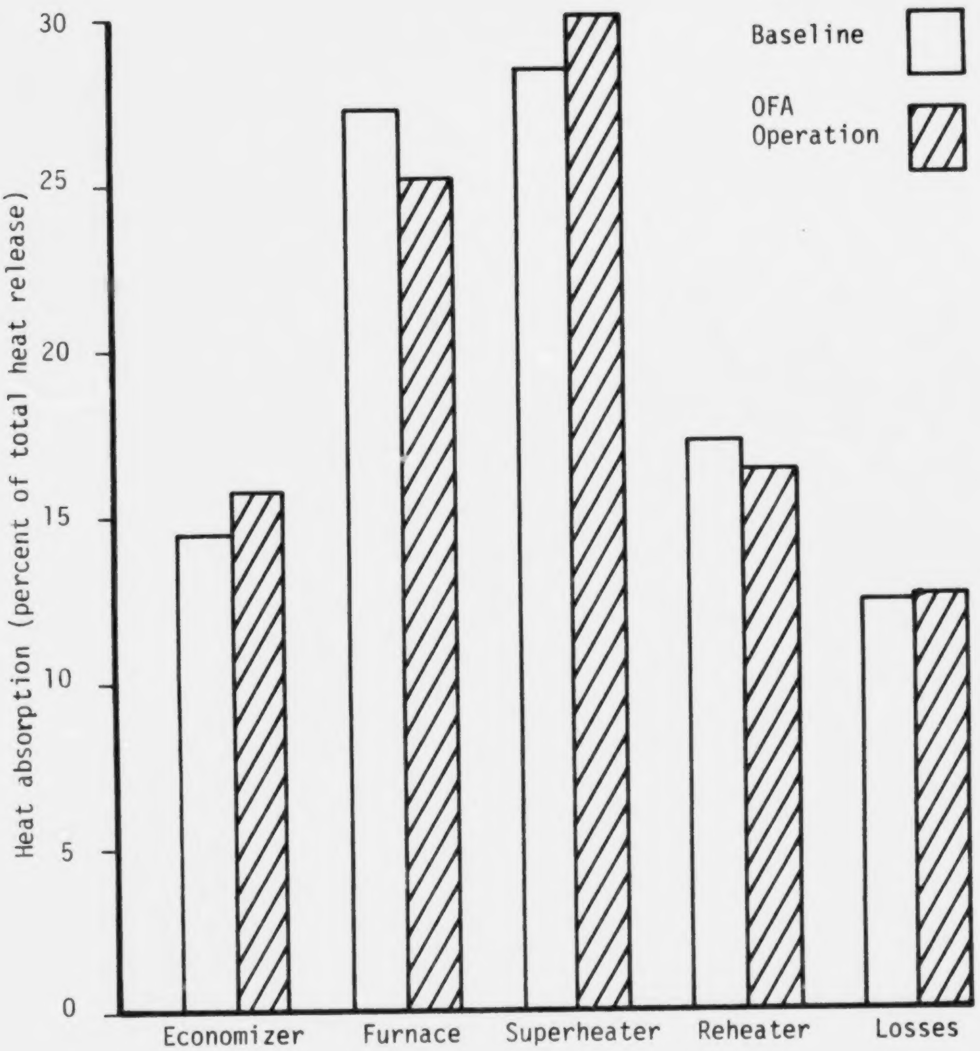


Figure 6-2. Heat absorption profile for Columbia Unit No. 1 (Reference 6-3).

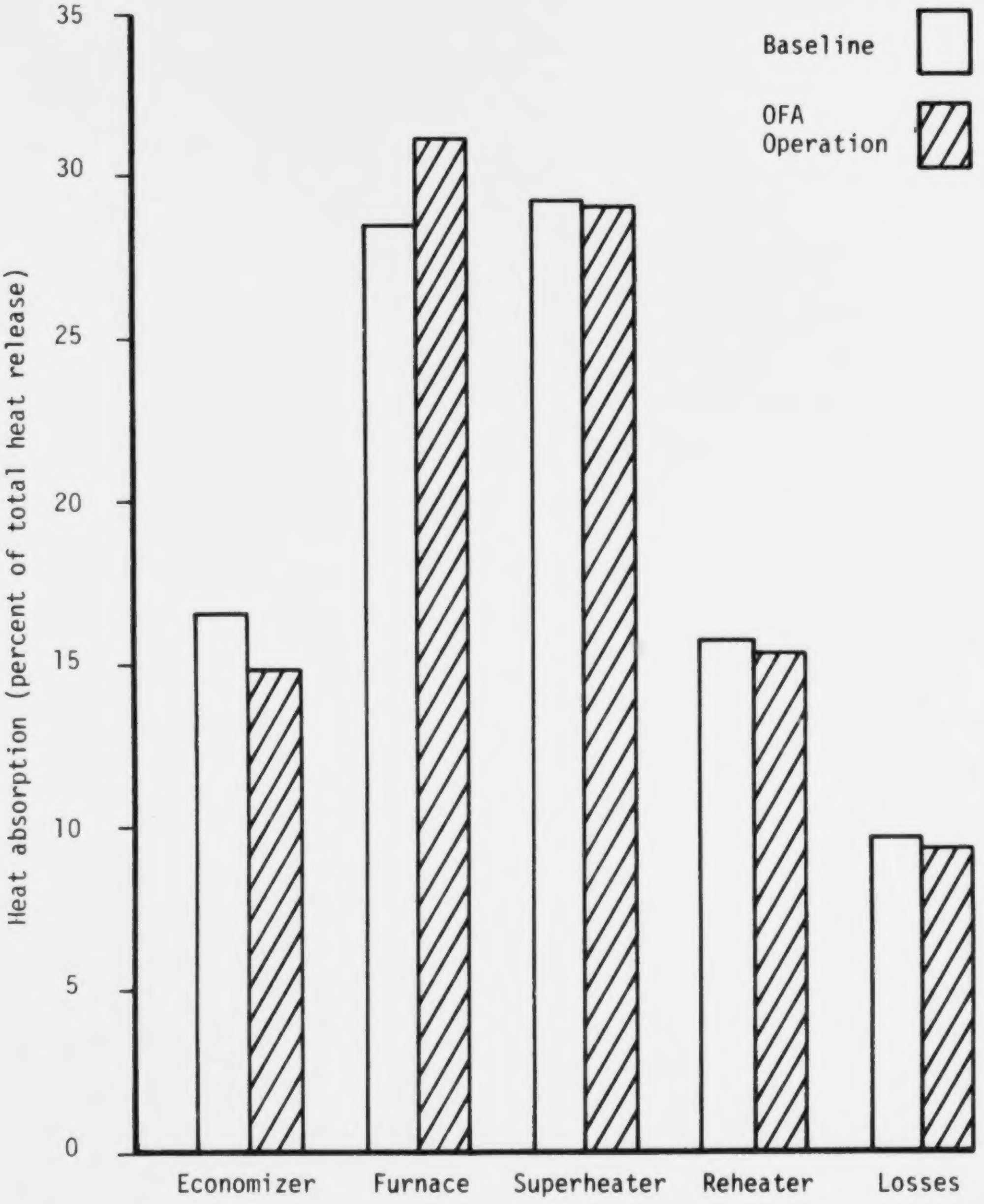
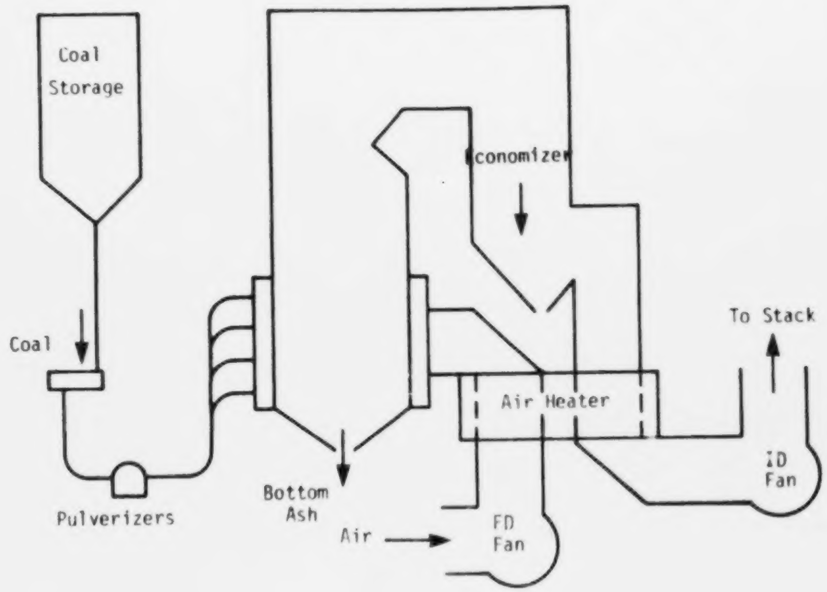


Figure 6-3. Heat absorption profile for Huntington Canyon Unit No. 2 (data from Reference 6-3).


Coal
Storage
Coal
Pulverizers
Economizer
Bottom
Ash
Air
FD
Fan
Air Heater
To Stack
ID
Fan

Stream	Input kg/s (lb/hr)			Output kg/s (lb/hr)				
Location	Pulverizer	FD Fan	Furnace Bottom	Economizer Outlet				
Material	Coal	Air	Ash	Total Gas	NO_x	SO_2	CO	Particulates
Baseline	13.0 (103×10^3)	142 (1.13×10^6)	0.835 (6.63×10^3)	154 (1.22×10^6)	87.6×10^{-3} (695)	0.404 (3.21×10^3)	3.36×10^{-3} (267)	0.528 (4.19×10^3)
BOOS	10.6 (84.1×10^3)	116 (0.922×10^6)	0.393 (3.12×10^3)	125 (0.994×10^6)	40.8×10^{-3} (324)	0.454 (3.60×10^3)	2.33×10^{-3} (18.5)	0.888 (7.05×10^3)
OFA	13.6 (108×10^3)	147 (1.17×10^6)	0.741 (5.88×10^3)	159 (1.26×10^6)	64.4×10^{-3} (511)	0.444 (3.52×10^3)	3.02×10^{-3} (24.0)	1.12 (8.92×10^3)

Figure 6-4. Overall mass balance for Barry Unit No. 2 boiler (Reference 6-1).

The impacts of NO_x controls on other indicators of boiler operations, such as carbon loss and boiler efficiency, were also investigated in tests on these three boilers. The carbon loss in flyash, averaged over all the tests, increased by about 0.25 percent for every 10 percent decrease in burner air. There was, however, a large scatter in the results as evidenced by the entries in the tables. The tables also show that boiler efficiencies were largely unaffected by OSC operation.

Corrosion rates were also measured on the tests by the use of corrosion coupons inserted in the furnace for 30-day periods. It was found that the average weight loss per unit area of the coupons increased by about 75 percent under OSC operation for Barry, while it remained essentially unchanged for Columbia and actually decreased by 25 percent for Huntington. However, the weight losses for Barry and Huntington were within the range of losses that would be expected for the oxidation of carbon steel for a 30-day period. So, the result of the corrosion coupon tests must be regarded as inconclusive. Still, furnace wall corrosion does not appear to be a major problem with OSC operation on tangentially fired boilers.

Emissions and other data for the three boilers were also taken under various conditions of furnace slagging for baseline as well as BOOS and OFA operation. It was expected that NO_x emissions would increase with increased slagging due to lower heat absorption in the furnace and resulting higher temperatures. For example, at Barry where the furnace outlet temperatures were measured, the temperatures under baseline full-load conditions rose by an average of 52K (125°F) when the furnace was extremely dirty as compared to when it was clean. Surprisingly, however, furnace conditions had a wide but inconsistent effect on NO_x emissions in all three boilers. Carbon monoxide emissions and boiler efficiencies also did not show any trends nor did heat absorption profiles change significantly. However, carbon loss decreased slightly with increasing furnace water wall deposits, presumably because the higher furnace temperatures promoted complete burnout.

Additional data on tangential coal-fired boilers are available from two other studies. A 350 MW boiler, Alabama Power Company's Barry No. 4 was tested under low excess air and BOOS firing (Reference 6-2). Particulate emissions increased from an average of 1.54 μg/J (3.57 lb/10^6 Btu) under baseline conditions to 2.38 μg/J (5.53 lb/10^6 Btu) under low NO_x

operation. Carbon loss in flyash actually decreased from an average value of about 25 percent baseline to 17 percent for low NO_x. No discernible differences were detected in corrosion rates or boiler efficiency. The boiler operates with five levels of burners. Boiler derate of up to 20 percent occurred with one tier on air only and close to 50 percent with two tiers on air only.

In two other test programs, the 800 MW, Salt River Project, Navajo No. 2 boiler was tested under low excess air, BOOS, and OFA firing; the 350 MW, Public Service Company of Colorado, Comanche No. 1 boiler was tested under OFA firing (Reference 6-4). The Navajo No. 2 boiler did not require derating with the top tier of burners on air only out of a total of seven burner levels. But the particulate loading increased from an average of 1.58 μg/J (3.68 $lb/10^6$ Btu) to 2.29 μg/J (5.33 $lb/10^6$ Btu) when going from baseline to low NO_x operation. Carbon loss did not vary much, nor did corrosion rates or boiler efficiency. Particulate size distribution also did not change very much on a percentage basis with low NO_x firing. For the Comanche No. 1 boiler, the particulate loading actually decreased from an average of 1.35 μg/J (3.15 $lb/10^6$ Btu) at baseline to 1.07 μg/J (2.49 $lb/10^6$ Btu) at low NO_x operation. Carbon loss in flyash also decreased from 0.60 percent at baseline to 0.43 percent at low NO_x corrosion, efficiency and particulate size distribution data were not obtained for this boiler.

In summary, OSC has been shown to be an effective NO_x control technique for tangential coal-fired boilers. Of the two common methods for implementing OSC, namely OFA and BOOS, the former is to be preferred in cases where a lack of spare pulverizer capacity would result in derating with BOOS. OFA ports are included in all new post-NSPS tangential utility boiler designs. Older boilers can be retrofitted with OFA ports, if necessary, to prevent boiler derating with BOOS, though retrofit OFA is generally less effective in reducing NO_x than BOOS. OSC does not result in any other major adverse effect, except for potential increases in dust loading, as observed in some boilers. This may in some cases necessitate installation of larger or more efficient dust collection devices. However, no change in particle size distribution was reported. No significant changes in heat absorption profiles were noted. Superheater spray attemperation increased substantially in some cases but were still well within normal design limits. Reheater attemperation did not increase with OSC. The efficiency of the boilers remained, by-and- large, unaffected. Finally, corrosion rates did not increase significantly with OSC operation, based on tests with corrosion probes.

6.3 HORIZONTALLY OPPOSED COAL-FIRED BOILERS

A number of studies have been conducted to evaluate the effects of NO_x control techniques on horizontally opposed coal-fired boilers (e.g., References 6-2, 6-4, 6-5, 6-7, and 6-15). Some data have been reported on potential adverse affects resulting from NO_x control measures such as excessive slagging and corrosion, loss in efficiency, boiler derating, increased dust loading, etc. Test results are also available on horizontally opposed coal-firing units equipped with low NO_x burners. In general, it has been found that low NO_x operation of horizontally opposed boilers does not result in serious side effects with the exception of boiler derating associated with burner out of service (BOOS) firing. Also, although short-term tests with corrosion coupons do not indicate increased furnace wall corrosion rates with low NO_x operation, long-term tests are underway to resolve several uncertainties associated with the short-term tests.

In an Exxon study (Reference 6-2), the 480 MW, B&W, Georgia Power, Harllee Branch No. 3 boiler, and the 800 MW, B&W, Arizona Public Service, Four Corners No. 4 boiler were tested for particulate emissions, corrosion, efficiency, and carbon loss under several NO_x control modes of operation. The Harllee Branch boiler had a baseline NO_x emission of 711 ppm. Low excess air reduced this by 10 percent. Staging with four to six burners of the top burner row on air only reduced NO_x emissions by one third without any reduction in load. With all 10 burners on the top row on air only, the NO_x emissions decreased by half, but also resulted in a load reduction of 17 percent from 480 to 400 MW. Reducing load alone by 17 percent without OSC or LEA decreased NO_x by only about 20 percent. Particulate emissions from this boiler did not increase significantly with low NO_x operation; an average of 1.44 μg/J (3.36 $lb/10^6$ Btu) was measured at baseline compared to an average of 1.60 μg/J (3.72 $lb/10^6$ Btu) at low NO_x conditions. Carbon loss in flyash also increased from 3.8 percent on average at baseline to 9.0 percent on average at low NO_x conditions. Changes in boiler efficiency were negligible, and corrosion rates as measured on corrosion coupons indicated wide scatter in the results and no evidence of higher rates associated with low NO_x firing.

The Four Corners boiler had a baseline NO_x emission of 935 ppm. BOOS firing, by having from 8 to 12 burners on air only, reduced NO_x emissions by approximately 50 percent without a reduction in load. Some firing patterns, however, did result in a boiler load reduction from 800 MW down to 600 MW. During the course of some BOOS tests, about 0.2 pound of water per pound of coal fired was injected into the furnace by the operator to help improve precipitator efficiency. This resulted in up to 80 ppm additional reduction in NO_x emissions. The particulate emissions and carbon losses actually decreased with low operation. An average of 3.56 μg/J (8.28 $lb/10^6$ Btu) of particulates and 0.61 percent of carbon in flyash under baseline firing reduced to 3.00 μg/J (6.99 $lb/10^6$ Btu) and 0.32 percent, respectively, under low NO_x firing. Corrosion and efficiency measurements exhibited no significant changes.

Due to the uncertainties involved in extrapolating data from corrosion coupons to furnace wall wastage rates, long-term data on corrosion of actual furnace tubes are needed. Thus, Exxon has installed furnace tube panel test specimens on the 500 MW, Foster Wheeler, Gulf Power Company, Crist Station No. 7, horizontally opposed coal-fired boiler to evaluate the long-term effects of low NO_x operation on corrosion (Reference 6-7). The boiler was operated under low NO_x conditions, including low excess air and staging, for a period of about 1 year. Testing should be complete at present, and results should be available in the near future.

In another study, the 560 MW, B&W, West Penn Power, Hatfield Unit No. 3 was tested by KVB, Inc. (Reference 6-5). This horizontally opposed coal-fired boiler was tested for NO_x emissions and possible adverse effects under BOOS firing and operation with flue gas recirculation (FGR). Baseline NO_x emissions of about 900 ppm were reduced by 35 percent by putting 10 out of 40 burners on BOOS, and reductions of up to 17 percent were achieved with 15 percent FGR. Combination of BOOS and FGR resulted in about a 10 percent further reduction in NO_x from levels achieved using BOOS alone. BOOS operation resulted in approximately 50 MW derate of the boiler, and a decrease in efficiency of up to 0.3 percent. Operation with FGR and BOOS resulted in decreases in efficiency up to 1 percent. No corrosion or erosion tests were performed so the effects of FGR and/or BOOS on corrosion and erosion are not known for this particular boiler. No other operational difficulties or adverse effects were encountered. Stable flames and uniform combustion were obtained throughout the test program. Particulate loading, flyash resistivity and carbon carryover were essentially unchanged during low NO_x firing. No significant slagging or fouling of the tube surfaces was observed. Average tube metal temperatures remained essentially unchanged, and steam temperatures were maintained near normal levels with automatic control. High gas recirculation rates did not require use of additional reheat attemperation.

The Hatfield unit was also tested for polycyclic organic matter (POM) emissions by KVB, Inc. under baseline and low NO_x conditions. The low NO_x conditions tested were: BOOS (8 burners out of service on the rear wall, out of a total of 40 burners), 15 percent FGR, and 8 BOOS +15 percent FGR. The baseline and low NO_x tests were all carried out under similar load and excess air conditions. The load was maintained between 445 to 455 MW during the tests and the excess oxygen varied from 4.9 to 5.5 percent. The POM emissions from these tests as measured upstream of the precipitator are summarized in Table 6-6. Total POM emissions increased by about 30 percent due to BOOS operation, decreased slightly with FGR operation and increased by about 40 percent when BOOS and FGR operations were carried out simultaneously. The individual constituents of the total POM emission showed varied and somewhat inconsistent trends with low NO_x operation. For example, the anthracene/phenanthrene levels, which constitute about half of the total POM emissions, did not change significantly from baseline with BOOS firing, decreased by 18 percent from baseline with FGR operation, but increased by 29 percent from baseline with combined BOOS + FGR operation. As sampling and laboratory analysis methods for POMs are changing rapidly, these results should be treated with due caution. At present the only conclusion that can be drawn is that POMs are likely to increase slightly with OSC operation.

Exxon has tested a horizontally opposed coal-fired boiler retrofitted with the B&W dual register low NO_x burners. The 270 MW, B&W, Southern Electric Generating Company, E.C. Gaston Boiler No. 1 was tested and compared with a sister unit, Gaston Boiler No. 2, not equipped with the dual register burners (Reference 6-4). The boiler with regular burners had a

TABLE 6-6. SUMMARY OF POM EMISSIONS FROM HATFIELD UNIT NO. 3 MEASURED UPSTREAM OF ESP (Reference 6-5)

Substance	Baseline	BOOS Operation		FGR Operation		BOOS + FGR Operation	
	μg/MJ	μg/MJ	Percent Difference from Baseline	μg/MJ	Percent Difference from Baseline	μg/MJ	Percent Difference from Baseline
Athracene/Phenanthrene	54.3	54.6	+0.5	44.3	-18.5	70.1	+29.1
Methyl Anthracenes	16.3	14.8	-9.3	27.2	+66.9	30.0	+83.7
Fluoranthene	15.6	33.6	+114.5	7.49	-52.1	13.3	-15.2
Pyrene	4.55	15.8	+247.9	7.11	+56.3	14.3	+214.6
Chrysene/Benz(a)Anthracene	0.09	--	--	--	--	--	--
Total POM	90.9	18.8	+30.7	86.1	-5.3	127.7	+40.5

baseline NO_x emission of 595 ppm compared with a baseline of 387 ppm on the boiler with the new burners. Gaston No. 1 was also tested under LEA and BOOS firing. LEA reduced NO_x further by 29 percent. BOOS with one top row of burners on one wall on air only reduced NO_x to 240 ppm accompanied by a reduction in load to 250 MW. With the top rows of burners on both walls on air only the NO_x levels could be reduced to as low as 182 ppm at 190 MW.

No significant differences were observed in boiler efficiency and corrosion rates between the two units. The carbon loss in flyash for the Gaston No. 2 boiler under baseline conditions averaged 1.87 percent and the particulate loading averaged 2.31 μg/J (5.34 lb/10^6 Btu). The Gaston No. 1 boiler, with the retrofitted low NO_x burners, when operated under baseline conditions averaged 4.37 percent on carbon loss in flyash and 2.67 μg/J (6.21 lb/10^6 Btu) on particulate loading. The particle size distribution seemed to shift towards smaller particle sizes with LNB. For Gaston No. 2 over 90 percent by weight of particles were above 2.5 μm and about 2 percent less than 0.5 μm. For Gaston No. 1, with LNB, about 60 percent by weight of particles were larger than 2.5 μm and 10 percent smaller than 0.5 μm. The particle distribution in Gaston No. 1 did not change significantly when the boiler was operated under BOOS conditions. It should be mentioned that comparisons between two different boilers, even if similar in design, is subject to uncertainties as slight differences in operating conditions in the boilers can lead to significant differences in results. B&W claims that its new burners when operating under normal conditions do not result in adverse effects such as increased carbon loss or particle loading (Reference 6-15).

Predicted performance specifications on two similar B&W boilers, one with the standard cell burners and the other factory equipped with the new low NO_x burners, are summarized in Table 6-7 (Reference 6-16). The two units are identical except for burner design. Table 6-7 shows that only minor changes are expected in the process variables due to installation of the new burners. Note that Unit 2 with low NO_x burners operates with a slightly lower unit efficiency, and this is due to the higher excess air level employed with Unit 2. However, the incremental excess air is used to cool the installed OFA ports (not in use) that came with Unit 2 and is not a requirement of the low NO_x burners.

TABLE 6-7. COMPARISON OF PERFORMANCE SPECIFICATIONS ON TWO SIMILAR HORIZONTALLY OPPOSED COAL-FIRED BOILERS (Reference 6-16)

Process Variables	Unit 2 (Low NO_x Burners)	Unit 1 (Cell Burners)
Load Condition, MW	550	550
Number of Burners	40	40[a]
Furnace Volume m^3 (ft^3)	12,000 (425,000)	12,000 (425,000)
Furnace surface m^2 (ft^2)	6,595.5 (70,993)	6,595.5 (70,993)
Quantity kg/s (10^3 lb/hr)		
Steam	478.8 (3,800)	478.8 (3,800)
Fuel	57.6 (457)	57.6 (457)
Air	589.0 (4,675)	589.0 (4,526)
Temperature K (°F)		
Steam at SH outlet	813.7 (1,005)	813.7 (1,005)
Steam at RH outlet	813.7 (1,005)	813.7 (1,005)
Flue gas at economizer outlet	64.3 (698)	643.2 (698)
Pressure MPa (psig)		
Steam at SH outlet	18.17 (2,620)	18.17 (2,620)
Steam at RH inlet	4.15 (587)	4.15 (587)
Excess air at economizer outlet, %	22	20
Heat loss due to unburned combustion, %	0.3	0.3
Unit Efficiency	88.24	88.35

[a] 20 cell burners, 2 burners each

Process data on a pre-NSPS Foster Wheeler unit have recently been released (Appendix B). The boiler, designated Unit A, has a capacity of 456 kg/s (3.62 x 10^6 lb/hr) of superheated steam and 403 kg/s (3.2 x 10^6 lb/hr) of reheated steam. It has 24 high turbulence burners arranged in a 4 wide by 3 high array on two opposite walls. Tests were performed on the boiler, and the effect of excess air, load and staging on the boiler process variables were determined. The process data are shown in Table 6-8. The first column gives the baseline case at full load, 20 percent excess air and no burners out of service. No low excess air test data are available, but the effect of increasing the excess air level to 35 percent is shown in the second column. The NO_x emissions are seen to increase by about 5 percent over the baseline case.

The last two columns give the process data for the boiler operated at 75 percent MCR. The effect of a reduction in load alone is shown in column 3, where the NO_x emissions are 17 percent below the baseline level. In column 4, the combined effect of a load reduction and staging is shown. Since this unit is not equipped with OFA ports, staging was accomplished by taking the top eight burners (4 from each wall) out of service. OSC operation in this unit is therefore accompanied by a loss in capacity. The decrease in NO_x emissions due to staging is substantial: an approximately 50 percent reduction compared to the baseline level, and a 40 percent reduction compared to the low-load, no-staging case.

Unit efficiency is not affected by staging. As seen from Table 6-8, efficiency seems to depend mainly on the overall excess air level which controls the dry gas loss. Staging does tend to increase the unburned combustible losses, but since they form a small part of the total loss, their effect on unit efficiency is negligible. As mentioned earlier, one major detrimental effect associated with staging on this unit was a loss in capacity. Another problem that can occur with staging is that furnace conditions become unacceptable. In the tests given in Table 6-8 the furnace conditions, that is, the furnace wall and flame conditions, were monitored. During the baseline case (column 1) the flames were bright and clear, and the furnace walls were clean with slight accumulation of dry and sponge ash. As the burner stoichiometry was decreased the flames became hazier and started to fill the furnace. Also, slag accumulation increased and it became more plastic and started to run in certain spots on the furnace.

TABLE 6-8. COMPARISON OF PROCESS VARIABLES FOR A HORIZONTALLY OPPOSED COAL-FIRED BOILER AT BASELINE AND LOW NO_x CONDITIONS (APPENDIX B): UNIT A

Process Variables		I Baseline	II High Excess Air	III Load Reduction (LR)	IV BOOS (w/LR)
MCR	%	100	100	76	78
Main steam flow	Mg/hr (10^3 lb/hr)	420 (3333)	419 (3327)	321 (2550)	328 (2600)
Reheat steam flow	Mg/hr (10^3 lb/hr)	379 (3010)	370 (2940)	290 (2300)	296 (2350)
Furnace excess air	%	20.0	35.0	19.5	20.5
Burners out of service	Number out	0	0	0	8
Boiler drum pressure	MPa (psi)	17.24 (2500)	17.29 (2507)	17.56 (2547)	17.15 (2488)
Superheat steam pressure	MPa (psi)	16.41 (2380)	16.53 (2398)	16.53 (2397)	15.69 (2275)
Reheat steam pressure	MPa (psi)	3.61 (524)	3.56 (517)	2.83 (410)	2.83 (410)
Superheat steam temperature	K (°F)	806.5 (992)	807.0 (993)	811.5 (1001)	799.8 (980)
Reheat steam temperature	K (°F)	795.9 (973)	805.9 (991)	805.4 (990)	785.9 (955)
Air flow leaving AH	Mg/hr (10^3 lb/hr)	492 (3905)	568 (4505)	382 (3034)	400 (3175)
Gas flow entering AH	Mg/hr (10^3 lb/hr)	533 (4234)	610 (4843)	415 (3294)	435 (3451)
Air entrance temperature	K (°F)	340.9 (154)	337.0 (147)	347.6 (166)	348.2 (167)
Air leaving AH temperature	K (°F)	519.3 (475)	530.9 (496)	528.7 (492)	526.5 (438)
Gas leaving AH temperature	K (°F)	417.6 (292)	417.6 (292)	414.3 (286)	414.3 (286)
Gas leaving economizer temperature	K (°F)	665.4 (738)	669.3 (745)	641.5 (695)	643.2 (698)
Furnace draft	Pa (in. H_2O)	N.A.	N.A.	3359 (13.5)	2986 (12)
Fuel burned rate	Mg/hr (10^3 lb/hr)	45.99 (365)	47.75 (379)	36.16 (287)	38.18 (303)
Volumetric heat release rate	kW/m^2 (Btu/hr-ft^3)	154.26 (14915)	153.75 (14865)	121.36 (11734)	122.08 (11803)
Surface heat release rate	kW/m^2 (Btu/hr-ft^2)	218.01 (69155)	217.51 (68997)	171.50 (54402)	172.52 (54726)
Heat losses	%				
Dry gas		3.921	4.644	3.403	3.539
Hydrogen and moisture in fuel		4.398	4.623	4.204	4.304
Moisture in air		0.094	0.112	0.083	0.086
Unburned combustible		0.221	0.230	0.155	0.414
Radiation		0.190	0.190	0.250	0.250
Unaccounted for		0.500	0.500	0.500	0.500
Total losses	%	9.324	10.299	8.595	9.093
Efficiency	%	90.676	89.701	91.405	90.907

TABLE 6-8. Concluded

Process Variables		I Baseline	II High Excess Air	III Load Reduction (LR)	IV BOOS (w/LR)
Coal ultimate analysis	% by wt.	9.68	10.72	9.33	8.82
Ash	% by wt.	2.59	3.18	2.86	2.75
H_2	% by wt.	4.52	4.58	4.28	3.99
C	% by wt.	65.56	64.09	65.42	65.27
H_2O	% by wt.	7.10	6.90	7.88	9.37
N_2	% by wt.	1.42	1.31	1.26	1.35
O_2	% by wt.	9.13	9.22	8.97	8.45
Heating value	kJ/kg (Btu/lb)	27630 (11879)	26558 (11418)	27628 (11878)	26393 (11347)
Flue gas analysis	% by vol.				
CO_2		13.942	12.355	14.101	14.103
H_2O		8.701	8.105	8.591	8.469
SO_2		0.207	0.230	0.231	0.224
Gas emission data					
NO_2	ng/J (lb/10^6 Btu)	471 (1.1)	496 (1.2)	392 (0.91)	236 (0.55)
SO_2	ppm	2209	1908	2503	2554
CO	ppm	115	100	44	128

Foster Wheeler judged the conditions in the furnace to be unacceptable at burner stoichiometries of approximately 90 to 95 percent -- the estimated level during the test in column 4. Hence, although OSC operation of this unit resulted in substantial decreases in NO_x emissions, it caused a 25 percent derating of the unit and furnace conditions deemed unacceptable for long term operation.

In summary, test results on horizontally opposed coal-fired boilers indicate that low excess air, staging and low NO_x burners are all successful in reducing NO_x emissions without major adverse effects. However, staging by taking burners out of service often does lead to boiler derating. Problems with slagging may also arise under OSC operation. Moreover, although corrosion does not seem to be a problem from results of short-term tests on corrosion coupons, the question cannot be definitely resolved until results of long-term corrosion tests on furnace tubes become available.

Other methods, such as flue gas recirculation, have also been found to reduce NO_x in these design units. However, the reduction in NO_x emissions by these methods is generally much smaller, due to the effects of fuel nitrogen, than that by staged combustion combined with low excess air firing. Moreover, additional testing would be required to ascertain that no side effects are associated with use of the other methods.

6.4 SINGLE WALL COAL-FIRED BOILERS

A number of coal-fired boilers with burners located on one wall have been tested under low NO_x operation and compared with operation under baseline conditions. The effect of low NO_x operation on furnace slagging, corrosion, efficiency, carbon loss, particulate emissions, etc., have been investigated on some units. In general, the effect of low NO_x operation on single wall coal-fired boilers is not expected to be substantially different from that discussed above for horizontally opposed coal-fired boilers.

The Tennessee Valley Authority has conducted extensive tests on its 124 MW, B&W, rear wall fired, Widows Creek Unit No. 5 (Reference 6-6). A sister unit, the Widows Creek Boiler No. 6, was used as a control for long-term corrosion tests. Tests were carried out over the whole range of boiler loads. Typical NO_x baseline emissions varied from about 560 ppm at full load (125 MW) to 320 ppm at 50 MW. The combustion modifications employed to reduce NO_x emissions were taking burners out of service and lowering overall excess air levels. NO_x reductions from 30 to 50 percent were achieved by applying these methods in combination. No boiler derating was encountered if only 2 burners out of a total of 16 were taken out of service at full load. At partial loads more burners could be operated on air only. However, at lower loads BOOS operation was not as successful in reducing NO_x and at 50 MW, where NO_x levels were already quite low, BOOS operation resulted in an increase in NO_x emissions.

Particulate emissions from the Widows Creek No. 5 boiler increased under low NO_x conditions, but the increased amounts were not considered significant. Carbon loss in flyash, however, increased by about 30 percent at full loads. Efficiency was also adversely affected by low NO_x operation, decreasing by about 1 percent at full load and by about 0.7 percent at 50 MW. The results from corrosion tests were inconclusive. Corrosion was estimated both by the use of corrosion coupons and by actual measurement of tube wall thicknesses in Unit No. 5, which was operated under low NO_x conditions, and Unit No. 6, which was used as a control boiler. The results from the corrosion coupon tests might be invalid due to possible weight loss during acid cleaning. The wall thickness measurements are also subject to uncertainty, due to suspected errors in instrument calibration at the control boiler. Also, the tests were of short term duration (approximately 6 weeks). The low NO_x boiler showed a corrosion rate of about 40 mils/year on the side wall and about 12 mils/year on the division wall, as deduced from wall thickness measurements. These rates are an order of magnitude higher than the 1 to 3 mils/year corrosion rates experienced by furnace walls under normal firing conditions.

The boiler used for control purposes in the above tests, Widows Creek Unit No. 6, was also tested for low NO_x in an Exxon study (Reference 6-2). Baseline NO_x emissions from this boiler averaged 634 ppm at full load. A 10 percent reduction in excess air reduced NO_x emissions by 25 percent at full as well as reduced load under normal firing operation. The same percentage reduction in stoichiometric air to active burners under staged conditions reduced NO_x emissions by an average of 24 percent at full load and 28 percent at reduced load. Low NO_x operation of the boiler did not result in a significant change in efficiency. The percentage of carbon in flyash, however, increased from an average of 6.1 at baseline to 10.5 under low NO_x firing. The particle loading actually decreased from an average of 2.7 μg/J (6.3 $lb/10^6$ Btu) at baseline to 2.1 μg/J (4.8 $lb/10^6$ Btu) at low NO_x operation. No corrosion tests were carried out for this boiler. No other side effects were noted under modified combustion.

In the same study (Reference 6-2) a 320 MW Foster Wheeler boiler, Crist Station No. 6, operated by Gulf Power Company was tested for low NO_x emissions under LEA and BOOS. Reducing excess air to the burners, with or without staging, had a significant effect on NO_x emissions. The largest reduction in emissions occurred with the top row of 4 burners out of service from a total of 16. Under those conditions, NO_x emissions dropped from a baseline of 845 ppm to a low of approximately 520 ppm. The load capacity of the boiler, however, also decreased by about 25 percent. Some data are available for this boiler on the effect of low NO_x operation on other process variables. Particulate loading increased from 1.87 μg/J (4.34 $lb/10^6$ Btu) at baseline to 2.77 μg/J (6.45 $lb/10^6$ Btu) under low NO_x operation. The carbon loss in flyash increased from 5.08 percent at baseline to 8.15 percent at low NO_x conditions. The efficiency of the boiler changed from 88.5 percent at baseline to 88.1 percent at low NO_x conditions.. No data were available on corrosion data for this boiler.

The Widows Creek Unit No. 5 tested by TVA was also tested by Exxon in another study (Reference 6-7). Baseline NO_x emissions at full load for this boiler were 567 ppm at full load (125 MW) and 506 ppm at partial load (100 MW). These values are lower than the baseline emissions from the Widows Creek's sister Unit No. 6. The differences are attributed to the difference in coals fired and the fact that Unit No. 5 was much cleaner when tested than Unit No. 6. Low NO_x testing of Unit No. 5 involved staging, lowering overall excess air levels and changing burner register settings. For both load levels, lowest NO_x emissions were obtained by taking burners out of service from the top row, and setting the secondary air registers on the active burners at 20 percent open. Setting the air register at 20 percent open on the active burners reduces the amount of air available in the primary combustion zone, thus increasing the off stoichiometric effect of the staging process. It was also found that the overall excess air levels could be reduced to a greater extent when the active burner registers were at 20 percent open compared to 60 percent open. The minimum overall excess oxygen levels attainable, subject to the constraint of maintaining carbon monoxide emissions below 200 ppm, was about 3 to 3.5 percent under staged firing. At 125 MW, two burners could be fired on air only without a reduction in load, which resulted in NO_x levels as low as 468 ppm. At 100 MW, four burners could be placed on BOOS and caused NO_x levels to drop to 317 ppm.

The Unit No. 5 was also tested for particulates, carbon loss, corrosion and efficiency. The particulate emissions decreased from a baseline average of 2.3 μg/J (5.3 lb/10^6 Btu) to 1.9 μg/J (4.4 lb/10^6 Btu) under low NO_x conditions. The carbon loss on flyash also decreased from an average of 11.1 percent at baseline to 7.1 percent under low NO_x firing. The corrosion rates as measured by corrosion coupons showed a slight increase (less than 3 mils/year) in corrosion rates due to low NO_x firing. Finally, efficiency increased by an average of 1 percent when the boiler was operated under low NO_x conditions. This was most likely due to the reduced levels of overall excess air maintained during the low NO_x tests. Note that these results are quite different from those obtained by the TVA tests on the same boiler. The effects of low NO_x operation on particulate emissions, carbon loss, and efficiency are exactly the opposite of those found in the TVA tests. In addition, the corrosion rates, although increasing in both series of tests under low NO_x conditions, show a much smaller increase in the Exxon tests.

The Exxon study (Reference 6-7) also reported the results of tests on the 270 MW, Foster Wheeler, single wall fired, Public Service Electric and Gas Company (New Jersey), Mercer Station Boiler No. 1. This boiler is a wet bottom unit and has limited operational flexibility. The baseline NO_x emissions were 1383 ppm, which is not uncommon for this type of unit. The furnace floor is relatively close to the bottom row of burners so that high gas temperatures are maintained in the lower part of the furnace which keeps the slag in a molten state. Lowering excess air had the greatest effect on NO_x emissions. NO_x levels were reduced by 24 percent by this method. Biased firing, which was accomplished by firing top row burners fuel lean and bottom and middle row burners fuel rich, reduced NO_x by only 16 percent from baseline. No derating occurred due to biased firing. Low NO_x operation of the boiler increased particulate emissions slightly from 1.1 μg/J (2.6 lb/10^6 Btu, average) at baseline to 1.2 μg/J

(2.9 lb/10^6 Btu). The carbon loss also increased from an average of 1.9 percent at baseline to 3.5 percent under low NO_x conditions. The particulate size distribution was not affected significantly by low NO_x operation. Corrosion rates as measured by corrosion coupons also showed no significant difference between baseline and low NO_x operations. The efficiency of the unit also did not seem significantly affected by low NO_x operation.

Data have recently become available on two front wall coal-fired units manufactured by Foster Wheeler Energy Corporation (Appendix B). One of the units is of a pre-NSPS design, Unit B, while the other unit is designed to meet NSPS requirements, Unit C. Both units employ the old standard FWEC Intervane Burner which produces a high turbulence, high intensity flame. (Newer units are being installed with the FWEC low NO_x, dual register burners which produce a reduced turbulence flame). Although direct comparisons between the two units are difficult due to the different capacities and types of coal fired, the differences in NO_x emissions may be largely attributed to changes in the design of the NSPS Unit. The most significant of these changes are the larger furnace design to provide lower burner zone liberation rates, and the inclusion of OFA ports to provide OSC operation without derating.

The pre-NSPS design, Unit B, has an MCR of 292 kg/s (2.32×10^6 lb/hr) of superheated steam and 256 kg/s (2.03×10^6 lb/hr) of reheated steam. Under those conditions the unit has a burner zone heat liberation rate of approximately 1.17 MW/m^2 (370×10^3 Btu/hr-ft^2). Emissions and some process data for the unit are shown in Table 6-9 for different operating conditions. The major variables are amount of excess air, load condition and degree of staging. Column 1 shows the near baseline conditions with 93 percent of MCR, 26.8 percent excess air and all 16 burners in service (no staging). The effect of reducing load to 75 percent MCR while maintaining other conditions invariant is given in column 2, where the NO_x emissions decrease by 10 percent. The effect of excess air at this reduced load is shown in column 3 where the excess air is increased to 53.7 percent which brings the NO_x emissions back close to the baseline level.

The effect of OSC operation by taking the 4 burners on the top tier out of service is given in columns 4 through 8. One of the major impacts of this operation is to derate the unit to 75 percent of its capacity. OSC also results in substantial NO_x reductions, even at relatively low degrees of staging. For example, the conditions of the test shown in column 4 are similar in load and excess air level to the test in column 2. The column 4 test has four upper burners out of service, but the idle registers are closed so that there is nominally no staging. However, the leakage of air from the out of service burners* is sufficient to create a staging effect, and this is demonstrated in the 22 percent drop in NO_x emissions from column 2 to column 4. Further reductions in NO_x emissions occur as the degree of staging is increased by opening the idle registers, first to 10 percent as in column 5 and then to 50 percent as in column 6. For these tests the load and excess air levels are similar to those in columns 2 and 4. The maximum decrease in NO_x emissions due to OSC alone (column 2 versus column 6) is 59 percent and due to combined OSC and low load (column 1 versus column 6) is 63 percent.

The effect of overall excess air level under OSC operation is shown by comparing columns 5 and 7, and comparing columns 6 and 8, for idle register settings of 10 and 50 percent, respectively. As expected NO_x emissions increase with excess air. Also, the sensitivity of NO_x emissions to excess air increases with increasing burner heat liberation rates. This is demonstrated in Table 6-10 where the change in NO_x emissions with excess air is shown for different burner liberation rates. Since BOOS firing usually involves operating the remaining burners at high heat release rates, the overall excess air levels during BOOS operation need to be carefully controlled. The sharp rise in NO_x emissions with increasing excess air at high burner heat release rates is probably due to increased flame turbulence as burner throat velocities exceed their design values.

During the tests reported in Table 6-9, the boiler was monitored for adverse effects on unit performance and operation. Carbon monoxide and unburned combustibles did not increase significantly during the low NO_x tests. However, there was a problem with slagging at high degrees of staging. During the normal firing tests (columns 1 through 3 in Table 6-9),

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*Boiler designs usually allow for some leakage of air through out-of-service registers to keep the burner components cool.

TABLE 6-9. COMPARISON OF PROCESS VARIABLES FOR A PRE-NSPS FRONT WALL COAL-FIRED BOILER AT BASELINE AND LOW NO_x CONDITIONS: UNIT B

Test Variable		1	2	3	4	5	6	7	8
		Baseline	Load Reduction	High Excess Air Load Reduction	BOOS	BOOS	BOOS	BOOS	BOOS
Load	% MCR	93	75	75	75	75	75	75	75
Excess air	%	26.8	26.8	53.7	27.5	28.2	24.5	53.3	56.7
Burners out of service		0	0	0	4	4	4	4	4
Idle registers	% open	--	--	--	0	10	50	10	50
Steam flow rate	kg/s (10^3 lb/hr)	271 (2150)	227 (1800)	220 (1745)	227 (1800)	227 (1800)	227 (1800)	227 (1800)	227 (1800)
Fuel flow rate	kg/s (10^3 lb/hr)	37.7 (299)	32.3 (256)	34.5 (274)	29.7 (236)	30.0 (238)	29.5 (234)	31.6 (251)	30.2 (240)
Air leaving AH	kg/s (10^3 lb/hr)	380.5 (3020)	325.7 (2585)	383.9 (3047)	313.9 (2491)	318.3 (2526)	303.9 (2412)	401.4 (3186)	383.8 (3046)
Gas entering AH	kg/s (10^3 lb/hr)	414.4 (3289)	354.8 (2816)	413.5 (3282)	340.2 (2700)	344.9 (2737)	330.1 (2620)	429.4 (3408)	410.6 (3259)
Coal ultimate analysis:									
Ash	% by weight	10.06	10.06	13.86	11.38	11.38	11.38	11.38	11.38
S	% by weight	0.66	0.66	0.55	0.66	0.66	0.66	0.66	0.66
H_2	% by weight	4.29	4.29	3.77	5.17	5.17	5.17	5.17	5.17
C	% by weight	60.54	60.54	56.60	59.90	59.90	59.90	59.90	59.90
H_2O	% by weight	9.25	9.25	8.18	9.60	9.60	9.60	9.60	9.60
N_2	% by weight	1.20	1.20	1.09	1.22	1.22	1.22	1.22	1.22
O_2	% by weight	14.00	14.00	15.95	12.07	12.07	12.07	12.07	12.07
Heating value	kJ/kg (Btu/lb)	24137 (10377)	24137 (10377)	22176 (9534)	23653 (10169)	23653 (10169)	23653 (10169)	23653 (10169)	23653 (10169)
Flue gas analysis:									
CO_2	% by volume	13.549	13.549	11.601	12.796	12.730	13.086	10.746	10.524
H_2O	% by volume	9.033	9.033	7.670	9.876	9.836	10.053	8.622	8.486
SO_2	% by volume	0.055	0.055	0.042	0.053	0.053	0.054	0.044	0.043
Gas emission data:									
NO_2	ng/J (lb/10^6 Btu)	619 (1.44)	555 (1.29)	632 (1.47)	423 (1.00)	387 (0.90)	228 (0.53)	533 (1.24)	456 (1.06)
SO_2	ng/J (lb/10^6 Btu)	507 (1.18)	456 (1.06)	512 (1.19)	494 (1.15)	469 (1.09)	473 (1.10)	503 (1.17)	494 (1.15)

TABLE 6-10. COMPARISON OF SENSITIVITY OF NO_x EMISSIONS TO CHANGES IN EXCESS AIR LEVELS WITH INCREASING BURNER HEAT LIBERATION RATES: UNIT B

Test Numbers		5-7	2-4	1-3
Load	% MCR	75	75	75
Burners in Service		16	12	12
NO_x change per percent excess air increase	ng/J/% (lb/10^6 Btu/%)	2.87 (6.67E-3)	5.85 (13.6E-3)	7.09 (16.5E-3)
Idle Registers	% Open	--	10	50
Burner Heat Liberation MW	(10^6 Btu/hr)	48.6 (166)	58.6 (200)	58.6 (200)

the furnace side and rear walls had a covering of dry ash which is considered normal for this unit. The flames were bright and stable. In the low NO_x tests the slag and flame conditions varied with degree of staging. For example, in the test shown in column 8 of Table 6-9, the idle registers were open 50 percent and the overall excess air level was about 60 percent. The stoichiometry at the active burners was approximately 120 percent. The furnace conditions in this test were about the same as during normal firing. As excess air was lowered, increased slag formation occurred in the lower furnace. At 25 percent excess air and 50 percent open idle registers (column 6 of Table 6-9) slag was running rapidly on the rear wall creating conditions unacceptable for continuous operation. The active burner stoichiometry for this test was approximatey 90 to 95 percent. Flame conditions also became hazy at lower burner stoichiometry, although they were stable. Due to the problems associated with high degrees of staging, FWEC recommends that burner stoichiometry be maintained above 95 percent in their units (Appendix B).

The NSPS design, Unit C, has an MCR of 117 kg/s (9.29×10^5 lb/hr) of superheated steam and 93.2 kg/s (7.40×10^5 lb/hr) of reheated steam. The unit is designed with a low burner zone liberation rate of 678 kW/m^2 (215×10^3 $Btu/hr\text{-}ft^2$) (Cf. the pre-NSPS unit B which has a value of 1170 kW/m^2 (370×10^3 $Btu/hr\text{-}ft^2$) at MCR). The unit is also equipped with OFA ports. Hence, OSC Operation is possible without loss in capacity. Test data for emissions and process variables are shown in Table 6-11. The major variables tested are amount of excess air, load conditions and degree of staging. The first four columns represent tests without OSC. The OFA ports were kept closed during these tests. The test in column 1 is a baseline test at full load and about 20 percent excess air. The effect of a change in load, while maintaining excess air levels approximately constant, is shown by columns 2 and 3 which are at 93 and 68 percent MCR, respectively. NO_x emissions are seen to drop by approximately 30 percent for a 30 percent decrease in load. The effect of excess air with no staging is shown in column 4, which has the same load condition as the test in column 2. The change in NO_x with excess air is 6.23 ng/J ($14.5\ 10^{-3}$ $lb/10^6$ Btu) for each percent change in excess air at near maximum load conditions.

The data for Unit C operation under OSC are shown in columns 5 through 7. In all these tests the OFA ports were 100 percent open. Column

TABLE 6-11. COMPARISON OF PROCESS VARIABLES FOR AN NSPS FRONT WALL COAL-FIRED BOILER AT BASELINE AND LOW NO_x CONDITIONS: UNIT C

Process Variables		I Baseline	II Load Reduction	III Load Reduction	IV High Excess Air	V	VI	VII
MCR	%	100	92	68	92	100	92	92
Main steam flow	Mg/hr (10^3 lb/hr)	117 (930)	109 (865)	80 (637)	108 (861)	118 (935)	108 (860)	108 (855)
Reheat steam flow	Mg/hr (10^3 lb/hr)	93 (742)	NA	NA	NA	94 (746)	NA	NA
Furnace excess air	%	21.6	19.9	20	33.8	25.1	20.1	32.3
Overfire airport	% open	0	0	0	0	100	100	100
Boiler drum press.	MPa (psi)	14.49 (2102)	14.78 (2144)	13.81 (2003)	14.79 (2145)	14.51 (2104)	14.49 (2102)	14.77 (2142)
Superheat steam press.	MPa (psi)	13.03 (1890)	13.05 (1893)	12.96 (1880)	13.00 (1885)	13.03 (1890)	12.98 (1882)	13.03 (1890)
Reheat steam press.	MPa (psi)	3.41 (500)	3.46 (502)	2.50 (363)	3.46 (502)	3.45 (500)	3.46 (502)	3.45 (500)
Superheat steam temp.	K (°F)	810.9 (1000)	800 (980)	800 (980)	791 (965)	807 (993)	804 (988)	812.6 (1003)
Reheat steam temp.	K (°F)	810.9 (1000)	798 (977)	800 (980)	789 (960)	808 (995)	803 (985)	805 (990)
Airflow leaving AH	Mg/hr (10^3 lb/hr)	144.0 (1143)	126.5 (1004)	94.6 (751)	143.5 (1139)	149.1 (1183)	130.2 (1033)	144.1 (1144)
Gas flow entering AH	Mg/hr (10^3 lb/hr)	155.7 (1236)	137.1 (1088)	102.6 (814)	154.2 (1224)	160.8 (1276)	141.0 (1119)	155.1 (1231)
Air entrance temp.	K (°F)	284 (51)	320 (116)	321 (119)	315 (107)	278 (40)	316 (110)	311 (100)
Air leaving AH temp.	K (°F)	569 (565)	579 (582)	570 (566)	570 (566)	559 (547)	575 (576)	579 (582)
Gas leaving AH temp.	K (°F)	428 (311)	451 (353)	443 (338)	448 (346)	421 (298)	450 (350)	450 (351)
Gas leaving economizer temp.	K (°F)	648 (706)	646 (704)	629 (673)	642 (696)	643 (697)	647 (705)	651 (713)
Furnace draft	Pa (in. H_2O)	-150 (-0.60)	-220 (-0.90)	-170 (-0.70)	-200 (-0.80)	-190 (-0.75)	-190 (-0.75)	-250 (-1.0)
Fuel burned rate	Mg/hr (10^3 lb/hr)	46.22 (101.9)	41 (91)	31 (68)	42 (92)	46.3 (102)	42 (93)	43 (94)
Volumetric heat release rate	kW/m^2 (Btu/hr-ft^3)	185.34 (17920)	165.03 (15956)	123.31 (11922)	167.09 (16155)	185.45 (17930)	168.90 (16330)	170.47 (16482)
Surface heat release rate	kW/m^2 (Btu/hr-ft^2)	193.44 (61361)	172.24 (54636)	128.71 (40827)	174.39 (55318)	193.55 (61395)	176.28 (55919)	177.92 (56437)
Heat losses	%							
Dry gas		5.896	5.26	4.864	5.922	6.03	5.356	6.12
Hydrogen and moisture in fuel		5.23	5.11	5.06	5.094	5.25	5.088	5.176
Moisture in air		0.142	0.13	0.117	0.143	0.145	0.129	0.148
Unburned combustable		0.35	0.35	0.35	0.35	0.35	0.35	0.35
Radiation		0.25	0.25	0.25	0.25	0.25	0.25	0.25
Unaccounted for		0.50	0.50	0.50	0.50	0.50	0.50	0.50
Total losses	%	12.368	12.26	11.14	12.26	12.51	11.67	12.54
Efficiency	%	87.63	87.74	88.86	87.74	87.49	88.33	87.46

TABLE 6-11. Concluded

Process Variables		I Baseline	II Load Reduction	III Load Reduction	IV High Excess Air	V	VI	VII
Coal ultimate analysis								
Ash	% by wt.	8.10	7.38	7.38	7.38	8.10	7.74	7.74
S	% by wt.	0.50	0.24	0.24	0.24	0.50	0.37	0.37
H_2	% by wt.	5.40	5.36	5.36	5.36	5.40	5.38	5.38
C	% by wt.	67.78	67.34	67.34	67.34	67.78	67.56	67.56
H_2O	% by wt.	5.86	6.92	6.92	6.92	5.86	6.39	6.39
N_2	% by wt.	1.04	0.82	0.82	0.82	1.04	0.93	0.93
O_2	% by wt.	11.32	11.94	11.94	11.94	11.32	11.63	11.63
Heating value	kJ/kg (Btu/lb)	28426 (12221)	28342 (12185)	28342 (12185)	28342 (12185)	28426 (12221)	28384 (12203)	28384 (12203)
Flue gas analysis	% by vol.							
CO_2		13.621	13.841	13.830	12.606	13.259	13.801	12.453
H_2O		9.195	9.451	9.445	8.790	9.005	9.360	8.645
SO_2		0.037	0.018	0.018	0.017	0.037	0.028	0.026
Gas emission data								
NO_2	ng/J (lb/10^6 Btu)	387 (0.901)	358 (0.832)	268 (0.623)	435 (1.011)	247 (0.535)	184 (0.428)	266 (0.619)
CO	ppm	NA	39	26	35	NA	44	35

5 can be compared directly with the baseline case (column 1) since both are at full load and similar excess air conditions. Also, the test in column 6 can be compared with column 2 for 93 percent load and 20 percent excess air levels. Similarly, the test in column 7 is also at 93 percent load but at 32 percent excess air, and can therefore be compared to the test in column 4 which has similar conditions except that the latter was without the use of OFA Ports. From these sets of comparisons, it is seen that NO_x levels dropped by approximately 160 ng/J (0.37 $lb/10^6$ Btu) on opening the OFA Ports with all other conditions maintained constant. For the baseline case this represents a decrease of 35 percent in NO_x emissions. Also, under OSC operation, the change in NO_x with excess air level is 6.0 ng/J (14.0×10^{-3} $lb/10^6$ Btu) for each percent change in excess air at near maximum load (column 6 and column 7), which is comparable to the sensitivity under normal firing conditions.

The process variables in Table 6-11 do not indicate significant difference between normal and OSC firing, if variables such as load and furnace excess air levels remain unchanged. As mentioned earlier, there is a significant decrease in NO_x emissions when the OFA ports are opened, but the carbon monoxide emissions rise only by small amounts (39 ppm in column 2 versus 44 ppm in column 6) for the high load, low excess air condition. Unit efficiency also remains essentially unchanged. The effect of reduced load on the process variables is to lower all flowrates, including the volumetric and surface heat release rates which results in a reduction in NO_x emissions. However, since the flowrates decrease in proportion to the load reductions the unit efficiency is not significantly affected (compare columns 2 and 3). One the other hand, a change in excess air levels changes the air and gas flowrates through the system for a given fuel flowrate. The dry gas heat losses increase with an increase in excess air causing the unit efficiency to decrease (compare columns 2 and 4, and also 6 and 7). Reduced excess air levels are therefore desirable both for high efficiency and low NO_x emissions. However, very low levels can lead to unacceptably high carbon monoxide emissions. Also, low excess air levels combined with OSC operation can result in highly substoichiometric burner conditions which could cause problems with slagging and corrosion. Nevertheless, during the tests given in Table 6-11, slagging conditions were monitored and were found to be minimal both under normal and OSC operation. The overall excess air levels were always maintained at about 20 percent or above in those tests. Carbon monoxide emissions are also all within 50 ppm at those excess air levels.

Comparing the tests on Unit B and Unit C, the newer NSPS boiler (Unit C) is seen to have lower NO_x emissions. A direct comparison is not entirely justifiable due to the difference in the types of coal used in the tests. However, the lower NO_x emissions in the newer boiler are at least partly attributable to the larger furnace design and consequently lower burner zone liberation rates. The newer unit is also equipped with OFA Ports which avoids taking burners out of service during OSC operation. No derating therefore occurs during low NO_x operation of the newer unit.

In summary, the single wall coal-fired boilers tested to date show somewhat varied effects due to low NO_x operation. Boiler derating may occur in some units where OSC operation is performed by taking burners out of service. Efficiency losses due to low NO_x operation can be minimized if it is possible to maintain low overall excess air levels without excessive carbon monoxide generation. Increased carbon losses can probably be reduced or eliminated by ensuring proper air distribution to each burner. Particle loading may be expected to increase slightly in certain cases, but there is no evidence of a shift to smaller particle size. Slagging problems may also occur with OSC operation. On corrosion, the data are inconclusive. Corrosion rates seem to increase under low NO_x operation, but the extent or severity of the increase cannot be estimated at the present time. Long-term accurate tests on actual furnace water tubes are required to resolve the discrepancies observed on tests with corrosion coupons. Ongoing tests on a horizontally opposed coal-fired unit should help resolve the matter. No other major adverse effects are expected from low NO_x operation on wall fired coal burning boilers.

6.5 TURBO FURNACE COAL-FIRED BOILERS

The unique configuration of turbo furnace boilers is designed to produce lower NO_x emissions than uncontrolled wall fired boilers. Rawdon and Johnson have presented general papers on the performance of turbo furnaces (References 6-17 and 6-18). Published emission and process data of sufficient completeness from turbo furnaces have been minimal to date.

Due to the special design of the turbo furnace, certain combustion modification techniques can be tried on these boilers which would be difficult to implement on other designs. In particular the burners, which are directed at an angle downwards from horizontal, are equipped with velocity dampers and directional vanes by which the flow and direction of the combustion air can be independently controlled above and below the burner centerline. By changing the positions of the dampers and the vanes, it is possible to simulate overfire air injection in certain cases.

The furnace design also includes a throat or waist section. The flame basket is generally held in the lower part of the furnace below this throat. By installing overfire air ports above the throat section, it is possible to separate the combustion process into two distinct zones. Thus, if the lower part of the furnace is maintained very rich, a precombustion zone may be simulated. However, such conditions may also lead to an increased tendency to smoke with oil fuels. BOOS is not very effective as a NO_x control technique for these boilers due to the horizontal inline arrangement of the burners.

A series of tests were performed by Exxon on the Big Bend No. 2 turbo furnace burning pulverized coal to establish the NO_x reduction capability of combustion modification (Reference 6-2). Controls that were investigated consisted of low excess air, staged combustion with burners out of service, and directional changes of the combustion air vanes.

By far, the most effective technique was LEA resulting in about a 20 percent NO_x reduction. Excess air was reduced from 15 to 7 percent at near boiler steam generating capacity. No adverse boiler operating condition was reported for the LEA test. On the contrary, a slight net increase in thermal efficiency, although not reported, may be suspected from the reduction in flue gas stack temperature. Staged combustion with BOOS resulted only in slight NO_x reduction (10 percent), however, at a penalty of derating the boiler. When 8 of the 24 available burners were set on air only, the impact on boiler capacity was a reduction from 380 to 230 MW. Directional changes of combustion air vanes on this boiler also resulted in a slight NO_x reduction (11 percent) but, when combined with LEA, it proved to be the optimum retrofit control system for this unit with a total NO_x reduction of 27 percent at maximum operating load. The combination of LEA and directional air vane changes had no reported adverse impact on boiler operation. In fact, it may have caused a slight increase in efficiency as a result of lower flue gas stack temperatures.

6.6 TANGENTIAL OIL-FIRED BOILERS

Some process data are available on tangential oil-fired boilers from utility companies in California. The California utilities have gained considerable experience in NO_x reduction from oil- and gas-fired equipment. Generally tangentially fired boilers have lower NO_x emissions than wall fired boilers due to a lesser degree of flame interaction and lower flame intensity. In some cases, therefore, simple modifications such as low excess air operation have been sufficient to bring NO_x emissions down to acceptable levels. In other cases the usual combustion modifications used with oil and gas fuels, such as flue gas recirculation and off stoichiometric firing, have, in general, reduced NO_x emission to the desired values.

Table 6-12 shows a comparison of some process variables on South Bay Boiler No. 4 operated under baseline and low NO_x conditions at partial load (Reference 6-8). These tests were conducted prior to recent burner modifications implemented to increase the efficiency of the boiler while still meeting Southern California NO_x emission standards). These burner modifications are discussed later in this section following an analysis of the data presented in Table 6-12. The South Bay Boiler No. 4 is a Combustion Engineering tangentially fired cycling boiler, operated by San Diego Gas and Electric Company. The boiler has three levels of burners and can generate up to 198 kg/s (1.57 x 10^6 lb/hr) of steam at 786K (955°F) with a maximum drum pressure of 16 MPa (2300 psig). The furnace has a straight-through configuration without a gas/air heat exchanger. The combustion air is heated up to 394K (250°F) by means of steam coils. Under normal operation of the boiler the excess air level was maintained at levels higher than design values due to formation of local smoke pockets at lower excess air levels. That was found to be due to maldistribution of air at the burners. By closing the auxiliary air dampers down to around 90 percent while leaving the fuel air dampers 100 percent open, a more uniform airflow distribution was obtained which allowed operation at lower excess air levels. Baseline and low excess air operation are summarized in the first two columns of Table 6-12. The adjustment in the auxiliary air damper setting allowed excess oxygen to be decreased from 7.5 to 3.3 percent. In addition to decreasing NO_x by 17 percent, the boiler efficiency increased, as evidenced by the decrease in stack gas temperature, and the

TABLE 6-12. COMPARISON OF SOUTH BAY UNIT NO. 4 UNDER BASELINE AND LOW NO_x CONDITIONS UNDER PARTIAL LOAD (Reference 6-8)

Process Variables		Baseline	Low Excess Air	Off Stoichiometric Combustion
Load	MW	173	183	175
Excess Oxygen	Percent	7.5	3.3	5.5
Burners Out of Service		None	None	a from top tier
Burner Tilt	Degrees	+27	+27	+30
Flowrates:				
Steam	kg/s (10^6 lb/hr)	146 (1.16)	155 (1.23)	145 (1.15)
Fuel Oil	kg/s (10^3 lb/hr)	1.26 (10.0)	1.27 (10.1)	1.22 (9.7)
Temperatures:				
SH Steam	K (°F)	772 (930)	773 (931)	780 (944)
RH Steam	K (°F)	761 (910)	755 (899)	760 (908)
AH Air Out	K (°F)	375 (216)	386 (236)	381 (227)
Stack Gas	K (°F)	658 (724)	638 (688)	645 (702)
Oil Supply	K (°F)	365 (198)	366 (200)	366 (200)
Pressures:				
Steam Drum	MPa (psi)	12.1 (1760)	13.0 (1870)	13.1 (1890)
Oil at Burner	MPa (psi)	1.03 (135)	1.05 (138)	1.22 (162)
Furnace	kPa (in. H_2O)	1.6 (6.4)	1.0 (4.0)	1.2 (4.8)
Windbox/Furnace Differential W	kPa (in. H_2O)	1.5 (6.2)	2.5 (10)	2.5 (9.9)
E	kPa (in. H_2O)	1.4 (5.7)	2.2 (8.8)	2.5 (10)

TABLE 6-12. Concluded

Process Variables		Baseline	Low Excess Air	Off Stoichiometric Combustion
FD Fans:				
Discharge Pressure	kPa (in. H_2O)	4.85 (19.5)	4.28 (19.2)	5.67 (22.8)
Current	Amps	377	325	352
Fuel Air Damper	Percent open	100	100	100
Auxiliary Air Damper	Percent closed	0	87	90
Emissions:				
NO_x (at 3% O_2)	ppm	200	166	197
CO	ppm	10	7.5	2.5
Ringleman Smoke Density	ppm	0	0	0.25

increase in power output for approximately similar rates of fuel consumption. Lower excess air also had the advantage of reducing fan power consumption. The NO_x emissions for this boiler and the excess O_2 requirements over a range of loads is shown in Figure 6-5 for both baseline and low excess air operation. Figure 6-6 shows the fuel consumption and the stack gas temperature for these two modes of operation. For this boiler, a reduction in excess air levels from about 6 to 3 percent at full load led to a decrease in fuel consumption of approximately 5 percent.

Low NO_x techniques other than LEA were also tried on the South Bay Boiler No. 4 and were found to be less effective. The results of OSC operation by taking two burners out of service on opposite corners of the top tier are shown in column 3 of Table 6-12. Although the excess air level was lower than the baseline value due to more uniform air distribution obtained by closing the auxiliary air dampers 90 percent, the excess air level was higher than that at the low excess air mode of operation. Moreover the NO_x level was only marginally lower than the baseline emission. OSC operation was, therefore, not recommended as a NO_x control technique for this boiler. Reduced air preheat (RAP) was also tested as a means to control NO_x on this boiler. The boiler has a unique arrangement where steam coils are used to heat the combustion air. Reducing air preheat, therefore, does not lead to a direct increase in stack gas temperature and corresponding loss in boiler efficiency which would be the case in more common arrangements where flue gas is used to heat combustion air. However, for oil fuel no consistent trends in NO_x emissions were obtained which could be attributed to RAP.

Another unique aspect of this cycling boiler was its capability to operate over a large range of steam drum pressures. The drum pressure was accordingly varied to test whether it would have an effect on NO_x emissions. It was found that NO_x emissions increased with increasing steam pressure at high loads and decreased with increasing steam pressure at low loads. It was not recommended that this method be used for NO_x control. Finally, burner tilt was tested to test its effect on NO_x emissions. The tests were carried out with the steam coil air heater out of service due to a malfunction in its operation. The normal position of burner tilt was +30 degrees on oil fuel for steam temperature control. NO_x emissions were not affected by burner tilt in the range tested from

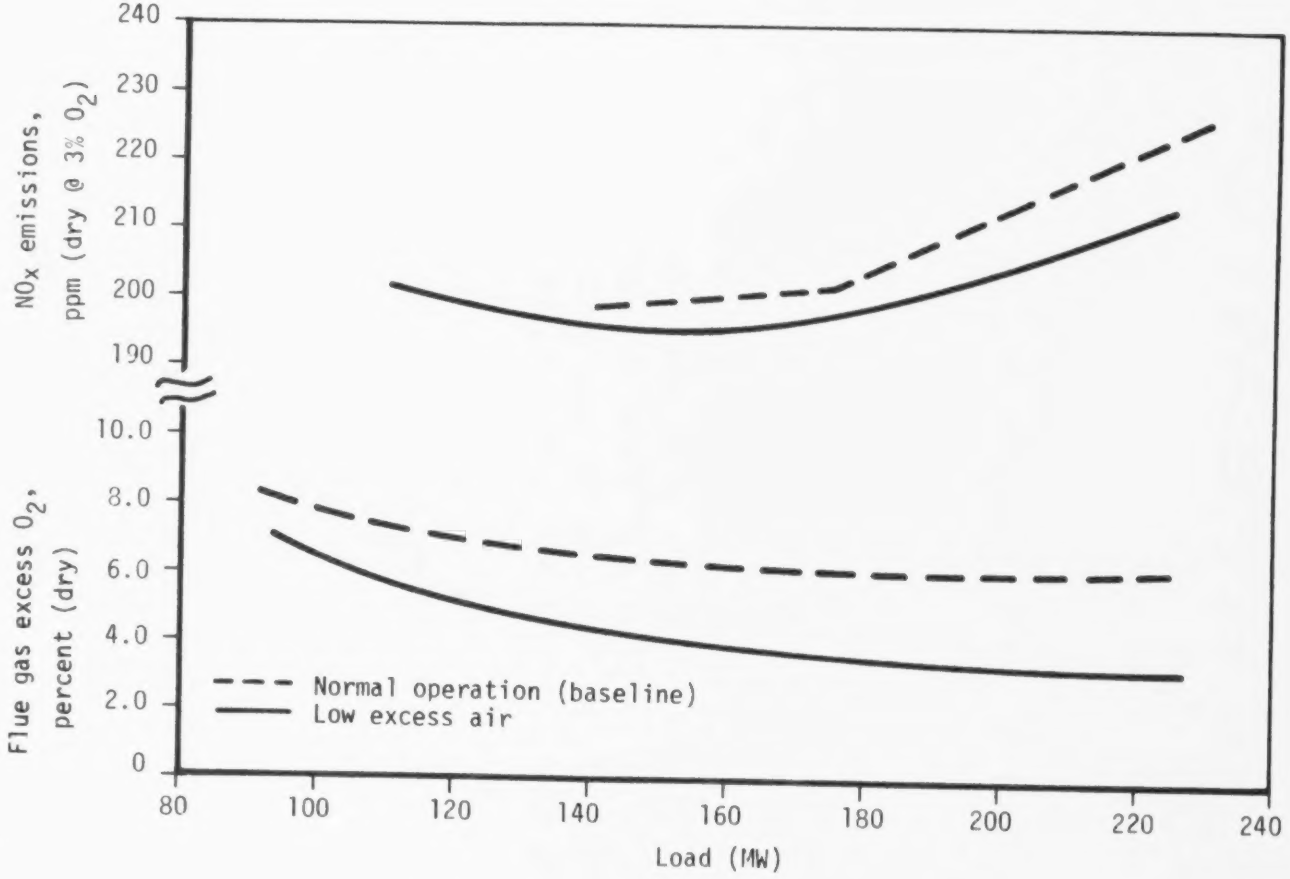

Figure 6-5. Comparison of NO_x emissions and minimum excess oxygen levels under baseline and low excess air conditions for South Bay Unit No. 4 (Reference 6-8).

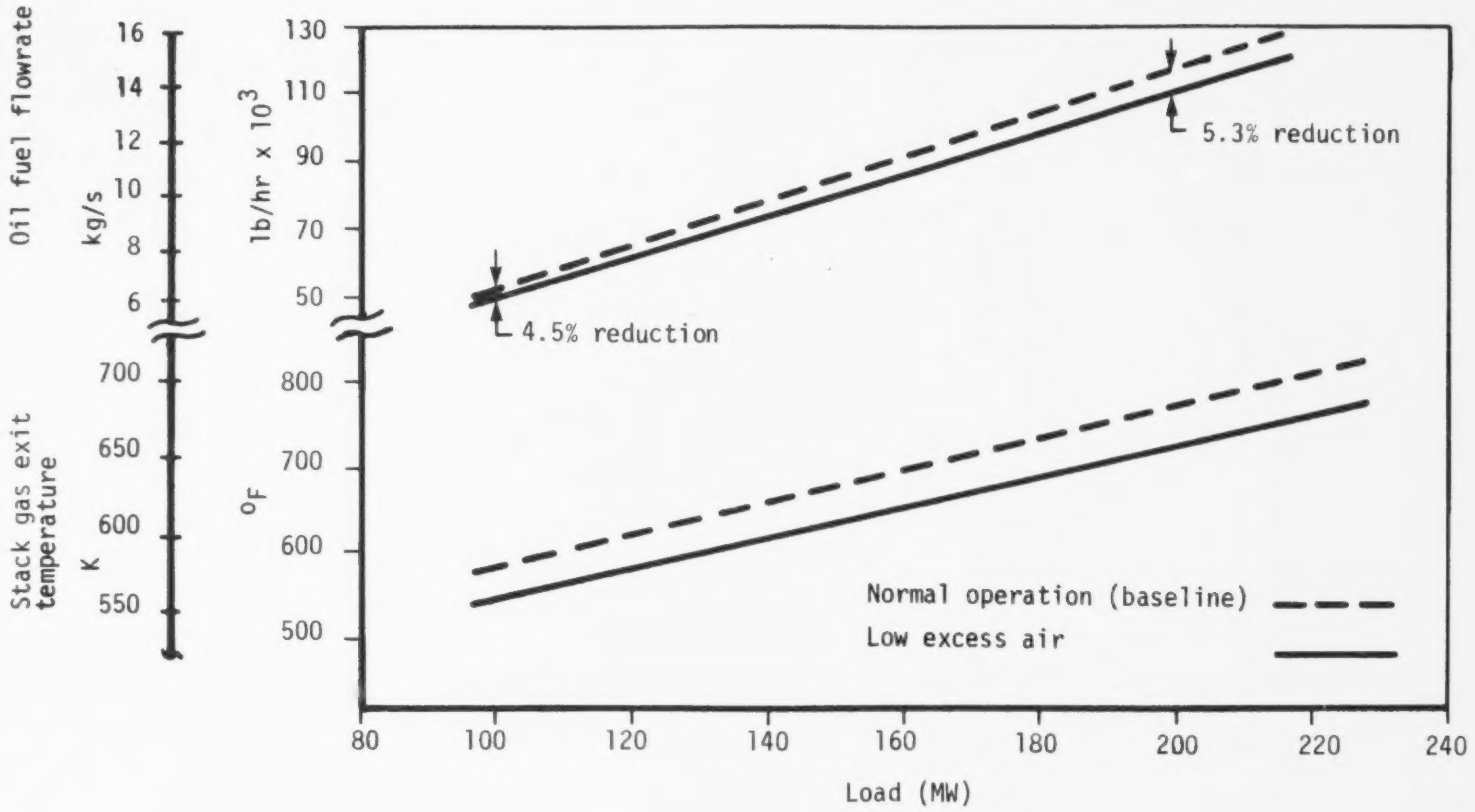

Figure 6-6. Comparison of oil consumption and stack gas temperature under baseline and low excess air conditions for South Bay Unit No. 4 (Reference 6-8).

+28 to +8 degrees. It was found, however, that under normal operating conditions (i.e., high excess air operation due to nonuniform airflow), the minimum excess oxygen level decreased with decreased burner tilt. As no tests were carried out under low excess air condition (uniform airflow) and with the air heaters in service, the effect of burner tilt under these conditions is not known. In general, operating variables such as steam pressure or burner tilt, which affects steam temperature, are not recommended for NO_x control due to the potential impact of these variables on plant operation and efficiency.

Subsequent to these tests investigated for the South Bay Unit 4, San Diego Gas and Electric Company recently installed new burners from an English manufacturer, designed to fire efficiently with low excess air. The objective of the burner retrofit was to improve the boiler efficiency while still maintaining the NO_x emission standard of 225 ppm at 3 percent O_2. A system-wide study by the utility had revealed that the efficiency of South Bay Unit 4 was significantly less than optimum. Although capable of meeting local NO_x regulations without combustion modifications, excess air requirements were high (15 to 20 percent versus a design of 10 percent) and steam temperatures were lower than normal (772K (930^{0}F) versus a design of 783K (950^{0}F)).

The LEA burner retrofit program by the utility has resulted in a 2 percent increase in boiler efficiency due to low excess air operation and improvement in steam temperature to design conditions. The effect of the new burners on NO_x emissions and flue gas oxygen requirements are illustrated in Figure 6-7. As shown, the LEA burners can meet the NO_x standard without further control over a wide boiler load range up to 200 MW or 87 percent of boiler capacity. Above this load, overfire air injection is utilized to keep NO_x below the 225 ppm limit (Reference 6-19).

Pacific Gas and Electric Company has retrofitted its Pittsburg Boiler No. 7 with overfire air ports capable of supplying 20 percent of the combustion air, and a flue gas recirculation system designed to dilute the oxygen in the windbox to 17 percent (Reference 6-9). This Combustion Engineering boiler, with five levels of tangential burners, has a design capacity of 677 kg/s (5.36 x 10^6 lb/hr) of steam. The baseline NO_x emissions are approximately 400 ppm at full load. With NO_x control techniques (FGR + OSC) the emissions decrease to about 280 ppm. PG&E,

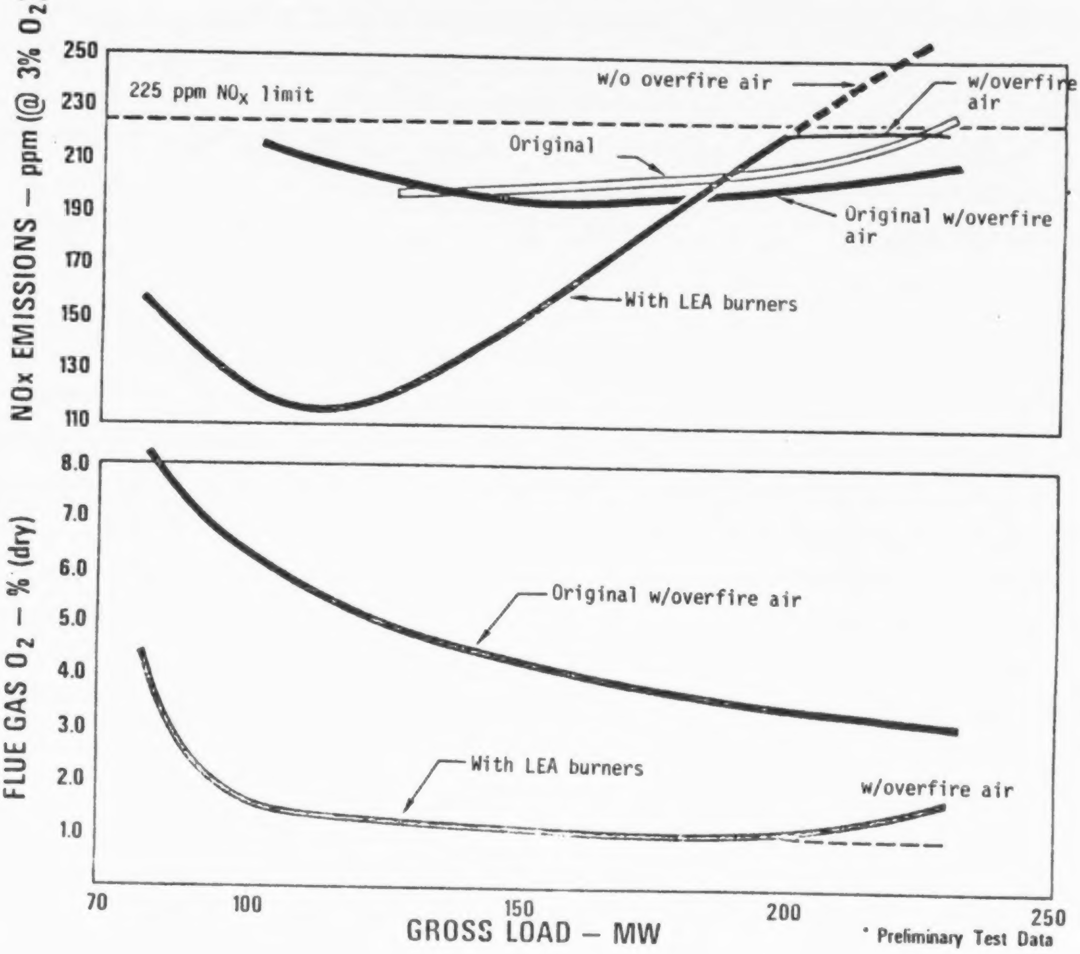

Figure 6-7. NO_x emissions and excess flue gas oxygen requirements of new LEA burners retrofitted on South Bay Unit 4. (Reference 6-19).

however, has had a number of problems with low NO_x operation on its boilers. The FGR fans on this boiler have caused vibration problems. It was found that the fans were limited to maximum temperature changes of 56K/hr (100^{o}F/hr). This necessitates slower unit startups from cold conditions, and also limits load changes to 5 MW/min. This is in contrast to the 75 MW/min attainable prior to the modification. There is also a tendency for the unit to smoke under low NO_x operation which, in turn, has limited the amount of overfire air to 50 percent of the design value. High water wall tube temperatures were also encountered in this unit, requiring some water wall inlet orifice changes.

Southern California Edison has modified six Combustion Engineering tangentially fired units for low NO_x operation (Reference 6-10). The units are rated at 320 to 335 MW, and have inverted furnaces so that the gases flow downwards in the furnace. There are three levels of burners and gas recirculation to the secondary air which were included in the original design for steam temperature control purposes. At 20 percent gas recirculation NO_x levels drop from a baseline value of 350 ppm at full load to values ranging from 215 to 245 ppm. This amounts to a reduction in NO_x emissions of about 30 percent. Removing two burners from service from opposite corners in the lower firing elevation in addition to FGR reduces emissions by 42 percent from baseline values. No adverse effects were reported with low NO_x operation (BOOS + FGR) of these boilers.

In summary, tangential oil-fired boilers can be modified to reduce NO_x emissions. For boilers with relatively low baseline emissions, reduction of NO_x emissions to acceptable levels may be obtained simply by low excess air operation. In many boilers this will require tuning and adjustments to ensure uniform air distribution to the burners. LEA operation has the advantage of increasing boiler efficiency and has, therefore, been recommended as standard operating practice for most utility boilers. Boilers which have higher baseline emissions will require flue gas recirculation, off stoichiometric firing or a combination of the two to reduce NO_x emissions to desired levels. In some cases, retrofit application of these modifications have led to problems such as vibrations, high tube temperatures and impaired load pick up response.

6.7 HORIZONTALLY OPPOSED OIL-FIRED BOILERS

A considerable body of data is available on horizontally opposed oil-fired boilers retrofitted for FGR and OSC firing to control NO_x emissions (e.g., References 6-7, 6-9 through 6-12). The reduction in NO_x emissions have, in some cases, been accompanied by a number of problems. This may be due to the need to reduce NO_x emissions to very low levels relatively quickly as required by local codes. Boilers designed with high volumetric heat release furnaces tend to encounter problems with OSC operation as the expanded combustion zone rapidly fills the small furnace. Also addition of FGR to the windbox results in high burner throat velocities which often result in flame instability and vibration problems.

Pacific Gas and Electric Company has reported on the modification of six of its horizontally opposed units for NO_x reduction to meet local air quality regulations (Reference 6-9). The Moss Landing Boiler No. 6, which is a Babcock and Wilcox unit capable of generating 640 kg/s (5.1×10^6 lb/hr) of steam, was modified to allow FGR to the windbox. The existing FGR fans, used to control steam temperature by injecting flue gas through the bottom hopper, were replaced with larger fans. New ducts, dampers and an air foil mixing device were installed. The system was designed to reduce the oxygen level in the windbox down to 17 percent. In addition to the FGR system, the unit was also modified to operate with BOOS. Out of a total of 48 burners, 8 on the top rows were operated on air only. The remaining burners were enlarged to accommodate the increased fuel flow. Up to 17 percent of the total combustion air could be injected through the BOOS ports. In addition to the hardware modification for FGR and OSC operation, the existing control and safety devices were modified to control and monitor the new system. New flame scanners, windbox oxygen analyzers and fully automated burner management systems were installed, and the combustion controls were modified for minimum air and for automatic proportioning of FGR to the windbox and hopper as a function of the load.

Table 6-13 gives a comparison of some process data on the Moss Landing Boiler No. 6 operated at partial load under baseline, BOOS, FGR, and BOOS + FGR modes (Reference 6-11). There seems to be very little difference in the process variables from one operating mode to another except in the NO_x emissions and the fan pressure and power requirements. The discharge pressure on the forced draft fan increased by about 15 percent when flue gas

TABLE 6-13. COMPARISON OF MOSS LANDING UNIT NO. 6 UNDER BASELINE AND LOW NO_x CONDITIONS UNDER PARTIAL LOAD (Reference 6-11)

Process Variables		Baseline	BOOS Operation	FGR at Windbox	BOOS + FGR Operation
Load	MW	503.6	501.9	501.0	500.3
Burner Firing Pattern		Normal	Upper row BOOS	Normal	Upper row BOOS
Gas Recirculation to Windbox	Percent	0.0	0.0	19.5	19.6
Overall Excess O_2	Percent	3.24	4.48	4.20	4.2
O_2 in Windbox	Percent	21.1	21.0	18.4	18.3
Fuel Oil Flow	kg/s (10^3 lb/hr)	32.61 (258.3)	32.34 (256.1)	32.52 (257.6)	31.34 (248.2)
SH Steam Flow	kg/s (10^3 lb/hr)	418.8 (3317)	422.1 (3343)	421.8 (3341)	422.1 (3343)
RH Steam Flow	kg/s (10^3 lb/hr)	354.3 (2806)	357.4 (2831)	357.6 (2832)	357.7 (2833)
SH Attemperator Flow	kg/s (10^3 lb/hr)	24.41 (217.1)	27.17 (215.2)	27.17 (215.2)	27.88 (220.8)
RH Attemperator Flow	kg/s (10^3 lb/hr)	0	0	0	0
SH Steam Pressure	MPa (psig)	25.38 (3681)	25.22 (3658)	25.38 (3681)	25.34 (3675)
RH Steam Pressure	MPa (psig)	2.74 (397)	2.74 (398)	2.75 (399)	2.74 (397)
SH Steam Temperature	K (^oF)	816 (1009)	815 (1007)	815 (1008)	816 (1010)
RH Steam Temperature	K (^oF)	814 (1006)	809 (996)	811 (1000)	810 (999)
Windbox Pressure	kPa (inch H_2O)	3.48 (14.0)	3.36 (13.5)	3.73 (15.0)	3.73 (15.0)
Furnace Pressure	kPa (inch H_2O)	3.11 (12.5)	2.59 (12.0)	3.11 (12.5)	3.19 (12.8)
Economizer Out Press	kPa (inch H_2O)	0.57 (2.3)	0.67 (2.7)	0.59 (2.4)	0.59 (2.4)

TABLE 6-13. Concluded

Process Variables		Baseline	BOOS Operation	FGR at Windbox	BOOS + FGR Operation
FD Fan No. 1 Discharge Press	kPa (inch H_2O)	4.35 (17.5)	4.35 (17.5)	4.98 (20.0)	4.98 (20.0)
FD Fan No. 2 Discharge Press	kPa (inch H_2O)	4.11 (16.5)	4.11 (16.5)	4.73 (19.0)	4.73 (19.0)
Flue Gas Recirculation Fans:					
Current Consumption	Amps	224	220	290	290
Inlet Pressure	kPa (inch H_2O)	-4.55 (-18.3)	-4.75 (-19.1)	-3.66 (-14.7)	-3.56 (-14.3)
Discharge Pressure	kPa (inch H_2O)	3.23 (13.0)	2.91 (11.7)	4.21 (16.9)	4.28 (17.2)
Inlet Damper Position	Percent open	30	30	45	42.5
Air Foil Damper Position	Percent open	0	0	100	100
Hopper Damper Position	Percent open	100	100	0	0
NO_x (3% O_2 base)	ppm	273	221	251	169
SO_2	ppm	2.5*	--	41.9*	46.4*
CO	ppm	1000+	1000+	1000+	1000+

*Data appear lower than expected, but no explanation available.

was recirculated through the windbox, while the power requirements of the FGR fan increased by approximately 30 percent. Note that the carbon monoxide levels were unacceptably high in all cases. Generally, the overall excess air levels had to be increased to bring carbon monoxide emissions down to reasonable levels (below 100 to 200 ppm). This increased excess air can, in turn, affect superheater and reheater steam temperatures, and also increase FD fan power requirements. This could lead to problems if the steam attemperators or the fans are operating near their maximum capacity.

The Moss Landing boilers, and other horizontally opposed boilers discussed in Reference 6-9, showed reduction in NO_x emissions at full load ranging from 33 to 50 percent from baseline when operated under OSC + FGR. In some of those boilers, OFA ports were installed, designed to inject up to 20 percent of the combustion air above the burner zone. All boilers had FGR systems installed capable of reducing excess oxygen in the windbox down to 17 percent. The combustion modifications resulted in a number of operational problems. The most common problems were flue gas recirculation duct and fan vibrations, furnace vibrations, and high furnace pressures. Duct vibration problems usually necessitated installation of splitter vanes and duct reinforcement. Fan vibration problems were resolved by reinforcing the fan housing. Furnace vibrations and associated flame stability problems were reduced by modifying the impeller air louvers to reduce the air velocity at the lip of the impeller. Higher excess air requirements to prevent smoking and excessive carbon monoxide generation were also encountered in some units. No accurate data were available on the effect of combustion modification on efficiency.

Southern California Edison Company (SCE) has also reported results of low NO_x operation on two sets of its horizontally opposed oil-fired boilers to satisfy emissions regulations (References 6-10 and 6-12). A set of 480 MW, Babcock and Wilcox units with divided furnaces were retrofitted with FGR to the windbox. The units have 32 burners each, divided into four rows, and came factory-equipped with OFA ports. In general, OFA firing reduced NO_x emissions by 14 percent, from a baseline level of 330 ppm at full load. In comparison, BOOS firing was capable of reducing NO_x by 30 percent. The optimum BOOS pattern was obtained by operating the second highest level of burners on air only. FGR alone decreased NO_x emissions by 9 percent. However, the combination of FGR + BOOS resulted in NO_x

reductions of 44 percent. FGR was also beneficial in that it reduced the minimum oxygen level by 1/2 to 1 percent. It was found that combined OFA and BOOS operation was not much more effective than BOOS alone and had the disadvantage of increasing the required minimum excess air levels to prevent smoke formation.

Another set of 750 MW, Foster Wheeler units was also retrofitted with an FGR to windbox system by SCE. The units have 16 burners each, with four levels of burners. OFA ports were included in the original design. These units have baseline NO_x emissions at full load of 700 ppm. The high level of NO_x emissions are due to the small furnaces and high heat release rates for these units. Operation with OFA ports reduced NO_x by 18 percent. With BOOS the reduction was 25 percent, again with the optimal BOOS pattern obtained by operating the next to highest rows of burners on air only. BOOS and OFA combined were not very effective and required an increase in overall excess air levels. FGR alone, at 15 percent gas recirculation, decreased NO_x emissions by 45 percent. A combination of BOOS and FGR resulted in a 59 percent NO_x reduction at 600 MW. Large reductions in NO_x emissions were accompanied by a reduction in boiler capacity due to problems with vibration and fan capacity. The maximum power generation, with NO_x emissions below the statutory limit of 225 ppm, was 680 MW. Some experiments were performed with water injection on these units. Spraying 0.6 kg of water per kg of oil reduced emissions by 43 percent at 600 MW. This is comparable to the reduction achieved by FGR. However, water injection, in contrast to FGR, increased minimum oxygen requirements and decreased boiler efficiency.

The problems encountered with low NO_x operation of the SCE units involved flame detection, flame instability, boiler vibration, and limited load capability. Flame detection problems arose due to changes in flame characteristics with combustion modification, rendering some of the conventional flame scanners inadequate. Addition of flicker (visible light) scanners did not completely resolve the problem. Flame stability problems were caused by the increased fuel flow in the active burners due to BOOS operation and the increased burner throat velocities resulting from the addition of FGR. Flame instabilities and pulsations also led to boiler vibrations. Extensive testing and burner modifications were required to resolve these problems. In the 750 MW boiler the modifications tested included adding diffusers to the oil guns, increasing burner throat diameter, extending oil guns further into the furnace and changing burner airflow distribution. Multiflame burner ("splitter") nuts, devices that delay fuel/air mixing, were also installed as they had the effect of increasing local fuel richness and reducing NO_x emissions by about 10 percent. Vibrations were finally reduced to an acceptable level by modifications which provided up to 10 percent tertiary airflow around the active oil guns. However, this resulted in an increase in minimum excess oxygen requirements from a normal value of 3 percent to 5.5 to 6 percent. The excess oxygen level was reduced to about 4 to 4.5 percent by subsequent modification involving the swirl vanes in the active burners. The increased excess air levels and additional head capacity requirements due to gas recirculation have caused the forced draft fan to reach maximum capacity at partial load. The maximum capacity of the boilers have been limited to 680 MW, which is much lower than 800 MW maximum rated capacity, and 750 MW maximum continuous rating of the boilers.

Exxon has reported the results of a test on the 330 MW, B&W, Public Service Electric and Gas Company (New Jersey), Sewaren Station Boiler No. 5 (Reference 6-7). The tests were limited to a maximum load of 285 MW as the high pressure feed water heaters were out of service during the testing period. At that load staged firing, taking 4 or 5 burners out of service from a total of 24, reduced NO_x levels by 22 percent. Injecting flue gas through the bottom of the furnace (not the windbox) reduced NO_x by only 7 percent. NO_x reductions of 16 to 24 ppm were obtained per 1 percent reduction in excess oxygen level. Reducing load by 25 percent from 285 MW decreased NO_x emissions by 19 percent. The boiler was also tested for particulate emissions under baseline and low NO_x conditions. The particulate loading under both firing conditions was the same 13 ng/J (0.03 lb/10^6 Btu). Particulate size distribution also did not vary significantly. Under baseline conditions 84.6 percent of the particles were greater than 2.5 μm and 8.2 percent were less than 0.5 μm. Under low NO_x conditions the corresponding percentages are 80.0 and 10.8. No flame stability or vibration problems were reported.

Foster Wheeler Energy Corporation has recently reported the results of low NO_x operation on a horizontally opposed oil fired unit (Appendix B). The unit was rated at 800 MW and was capable of producing 705 kg/s

(5.6×10^6 lb/hr) of main steam and 592 kg/s (4.7×10^6 lb/hr) of reheat steam. It was fitted with OFA Ports and was guaranteed at 500 ppm of NO_x at 3 percent oxygen. During construction, however, the NO_x limits were set at 250 ppm by the local authorities. A flue gas recirculation system was therefore added. During start up of the unit it became clear that OSC operation using OFA ports would not be capable of reducing NO_x emissions to the desired levels even with the FGR system. OSC operation with burners out of service was, therefore, tried and a program was initiated to determine the optional BOOS pattern. The results of the study are shown in Table 6-14 for various BOOS patterns. In all those tests, 8 out of a total of 32 burners were out of service and 15 percent of the flue gas was recirculated. The range of NO_x emissions shown corresponds to excess oxygen levels ranging from the smoke threshold limit (minimum value) to 1 percent above the minimum. As seen from the table, the second row of burners out of service gave the best results both for NO_x and minimum air requirements. However, the increased air flow through the burners due to addition of FGR caused severe flame instability and associated boiler vibration problems which limited the load to 630 MW -- approximately 80 percent of MCR.

As a consequence, an experimental burner modification program was initiated. Various burner modifications were tried and rejected since they did not improve flame stability. A burner modification which resulted in stable flame characteristics was the inclusion of a tertiary air nozzle and sleeve to provide a 10 percent air flow around the oil gun. The minimum excess oxygen level, however, increased and the boiler reached its forced draft fan capacity limit. Further modifications including reduction of the tertiary air to 5 percent and installation of swirl vanes on the top row of burners, have increased the boiler capacity to 680 MW (85 percent of MCR) with NO_x emissions at 225 ppm. Hence, operating within the constraints of acceptable boiler vibration and NO_x compliance has resulted in a boiler derate of 15 percent.

In summary, there is a potential for flame instability and furnace vibration problems when horizontally opposed oil-fired boilers are modified for low NO_x operation on a retrofit basis. These problems can be quite severe if NO_x reductions of the order of about 50 percent or more are required, and if the furnaces have high heat release rates. In such cases,

TABLE 6-14. BURNER OUT OF SERVICE TEST PATTERNS FOR A HORIZONTALLY OPPOSED OIL-FIRED BOILER

TEST	PATTERN	NO, PPM (DRY AT 3% O_2)	MIN O_2 %
1	○○○○|○○○○ ●●●●|●●●● ○○○○|○○○○ ○○○○|○○○○	195-225	3.1
2	○○○○|●●●● ○○○○|○○○○ ●●●●|○○○○ ○○○○|○○○○	200-245	3.5
3	●●●●|●●●● ○○○○|○○○○ ○○○○|○○○○ ○○○○|○○○○	205-275	4.6
4	●●●●|○○○○ ○○○○|●●●● ○○○○|○○○○ ○○○○|○○○○	220-265	4.0
5	●○●○|●○●○ ○●○●|○●○● ○○○○|○○○○ ○○○○|○○○○	230-265	4.1
6	●○●○|●○●○ ○○○○|○○○○ ○●○●|○●○● ○○○○|○○○○	235-275	4.2
7	○○●●|○○●● ●●○○|●●○○ ○○○○|○○○○ ○○○○|○○○○	240-325	4.8
8	●●●●|○○○○ ○○○○|○○○○ ○○○○|●●●● ○○○○|○○○○	245-300	4.5
9	○○●●|○○●● ○○○○|○○○○ ○○●●|○○●● ○○○○|○○○○	255-300	4.7

● BURNER OUT-OF-SERVICE, AIR REGISTER OPEN boiler derating by about 10 to 15 percent may occur. Usually the instability and vibration problems require extensive testing and modifications to permit acceptable operating conditions. Boiler operation may also become much more complex especially during startup and periods of load fluctuation. Some operations which are normally carried out by automatic control devices may require manual control with low NO_x firing. Installation of new control and safety equipment is often necessary. The particle loading and size distribution are not significantly affected by low NO_x operation. More data are needed on boiler efficiency. It is likely that some degradation in performance will occur if the low NO_x operation results in increased excess oxygen requirements. On the other hand, flue gas recirculation to the windbox has, in some cases, led to a reduction in minimum excess air requirements. Also installation of an FGR system will improve performance if the unit currently employs dampers and/or excess air to control steam temperatures. No effect on superheater or reheater temperatures have been noted, nor any on spray attemperators, due to low NO_x firing. However, such problems are site specific, and could possibly be encountered on other oil-fired boilers.

6.8 SINGLE WALL OIL-FIRED BOILERS

Some process data are available on single wall oil-fired boilers modified for NO_x control. Specifically, three 100 MW, B&W, San Diego Gas and Electric Company units (Encina Units No. 1, 2, and 3 (Reference 6-13)) were modified to achieve low NO_x emissions. These modifications were carried out in two steps: first to meet a December 31, 1971 local regulation of 325 ppm NO_x, and second to meet a January 1, 1974 regulation of 225 ppm NO_x. All three units exceeded these levels over much of their operating range under normal baseline firing.

The 1971 regulations were met by BOOS operation with 2 burners out of service out of a total of 10. A number of tests were carried out to determine the best BOOS pattern, register settings, and overall excess O_2 levels to achieve trouble free operation with low NO_x. The tests were subject to the constraints of keeping CO concentrations below 100 ppm and insuring no visible smoke plume formation (Ringleman No. less than 0.5). It was found that burners No. 2 and No. 4 (see Figure 6-8) out of service with

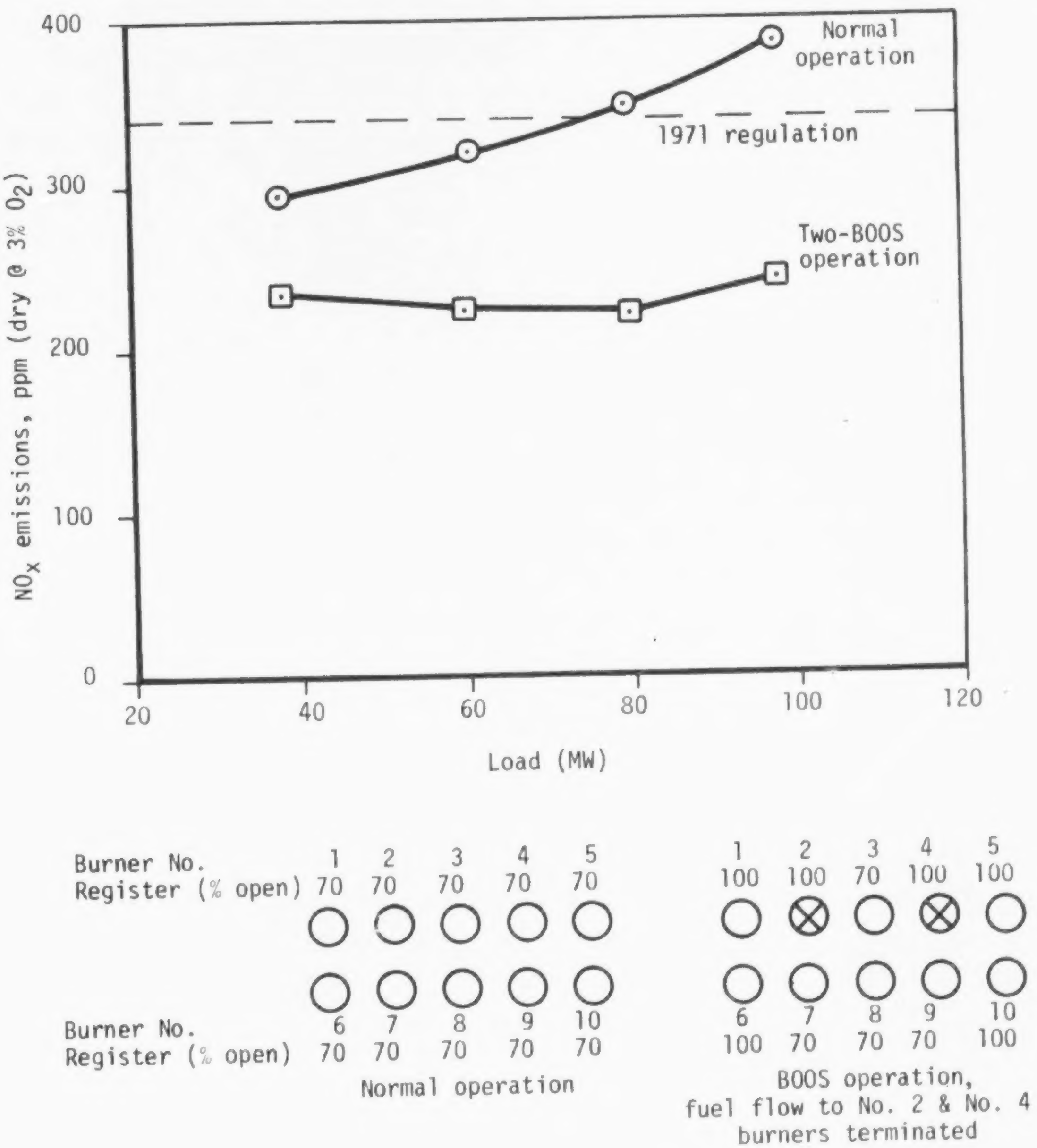

Figure 6-8. Comparison of NO_x emissions with normal and two-BOOS operation for Encina Unit No. 1. (Reference 6-13).

No. 2 and No. 4 registers full open resulted in the most satisfactory combination when both NO_x reduction and operational suitability were considered. Tests also showed that the wing burners (Nos. 1, 5, 6, and 10) received less air than the remaining burners so that they tended to smoke load, under fuel-rich operation. This problem was resolved by opening the wing registers 100 percent while keeping the registers of the remaining burners in service throttled to 70 percent open to force more air to the wings. The burner and register patterns before and after modification are shown in Figure 6-8.

With the burner and register patterns fixed, excess O_2 levels were varied to determine the minimum levels which would provide low NO_x operation without excessive CO or smoke emissions, and would not lead to problems such as flame instability, etc. Figure 6-9 shows a comparison of the recommended excess O_2 levels as a function of load under normal operation and the recommended values for operation with combustion modification for the Encina Unit No. 1. Figure 6-8 shows the NO_x emissions associated with these excess O_2 levels and modes of firing. Table 6-15 provides a comparison of some process data under baseline and low NO_x operation with two burners out of service.

Operation with lower excess air and combustion modification in the furnace sometimes led to a decrease in superheater temperatures in the Encina units at full load. Due to the restriction on excess airflow, the operator was obliged to rely on flue gas recirculation to increase superheater temperatures.* As shown in Table 6-15, the Encina Unit No. 1 had difficulty reaching a normal superheater temperature of 811K (1000°F), although the flue gas recirculation had been increased as evidenced by the increase in RC fan amperage. In another unit, Encina No. 3, the problem with superheater temperature occurred only at peak

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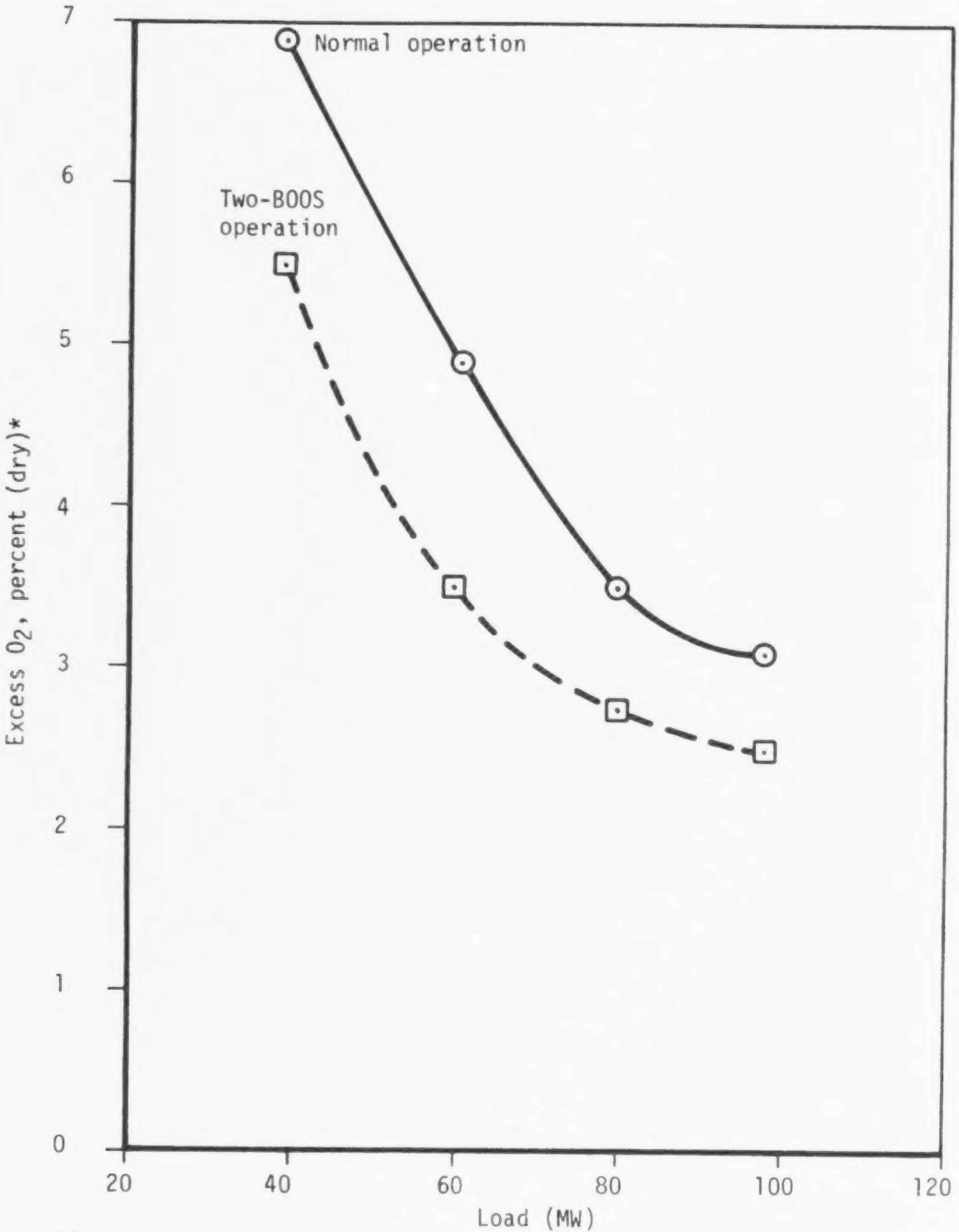
*In these units, recirculated flue gas is introduced between water tubes on the back wall of the furnace and not with the combustion air. Effect of the flue gas on NO_x emissions should therefore be small.



*As read in control room

Figure 6-9. Comparison of excess O_2 for normal and two-BOOS operation for Encina Unit 1 (Reference 6-13).

TABLE 6-15. COMPARISON OF ENCINA UNIT NO. 1 OPERATED UNDER BASELINE CONDITIONS WITH TWO BURNERS OUT OF SERVICE (Reference 6-13).

Process Variables		Baseline Operation	Two-BOOS Operation
Load	MW	98	98
Control Room O_2	Percent	3.0 to 3.2	2.5
Burners Out of Service		None	Nos. 2 & 4
Steam Temperature	K (^{o}F)	811 (1000)	800 (980)
Indicated Oil Flow	(Meter settings, arbitrary units)	960/1100	960/1100
Indicated Airflow		59/70	59/70
Oil Pressure	MPa (psi)		
Burner Supply		5.0 (725)	5.1 (740)
Burner Return		3.0 (440)	3.1 (450)
Oil Temperature	K (^{o}F)	374 (214)	374 (214)
Furnace Draft Pressure	kPa (inch H_2O)	-0.1 (-0.5)	-0.1 (-0.5)
AH Gas Out Temp.	K (^{o}F) N S	455 (360) 444 (340)	455 (360) 444 (340)
AH Gas In Temp.	K (^{o}F) N S	669 (745) 666 (740)	678 (760) 669 (745)
RC Fan	Amps	39	50
FD Fan	Amps N S	78 80	74 75
ID Fan	Amps N S	118 120	120 122
Measured NO_x	ppm N S	335 340	200 235
Measured CO	ppm N S	30 35	30 30

i.e., loads above 110 MW (the boilers are rated at an MCR of 110 MW). The superheater temperature at 114 MW fell from a normal of 811K(1000^{0}F) to 800K (980^{0}F), and the reheater temperature fell from a normal of 800K (980^{0}F) to 788K (958^{0}F).

Due to the increased oil flow to the burners in service, the oil tips and return passages had to be enlarged. The flames at each burner were observed to be satisfactory with no flame instability or blow off noted. Off stoichiometric firing also caused longer flames. Flame filled the furnace at the burner levels, and some intermittent flame carryover to the superheater inlet occurred. This did not result in short-term problems such as high tube temperatures, though. Off stoichiometric firing also resulted in the flame zone becoming very hazy and obscure. No other problems were encountered with two-BOOS operation. The boilers were operated for over 2 years in this mode with no signs of abnormal tube deposits nor chemical attack or erosion.

To meet the 1974 regulations (225 ppm NO_x), the boilers were operated with three burners out of service. The optimal BOOS pattern was obtained by terminating fuel flow to Nos. 2, 4, and 8 burners while the air registers were left at 100 percent open to act as air injection ports. The air registers on the remaining seven burners were set at 55 percent open. The oil burner tips were enlarged again to accommodate the increased flow in the active burners. The oil tip diameter, the tangential slot width, and the return passage diameter were all widened to provide adequate flow and desired flame structure. The operating excess O_2 level had to be increased generally above the levels recommended for two-BOOS or normal operation to curtail smoke formation. This did not lead to any measurable degradation in boiler performance. However as the boilers are mainly ID fan limited, an increase in excess air levels resulted in a peak load curtailment up to 5 MW in some cases.

Figure 6-10 shows the burner and register patterns used to achieve the 1974 standards in the Encina units when firing oil. It also shows NO_x emission from the Encina Unit No. 1 when operating with the excess O_2 levels shown in Figure 6-11. The range of excess O_2 levels shown in Figure 6-11 are the minimum required to operate the boiler without smoking while permitting the operator a certain range of flexibility. A comparison with Figure 6-9 indicates that the recommended levels of O_2 with

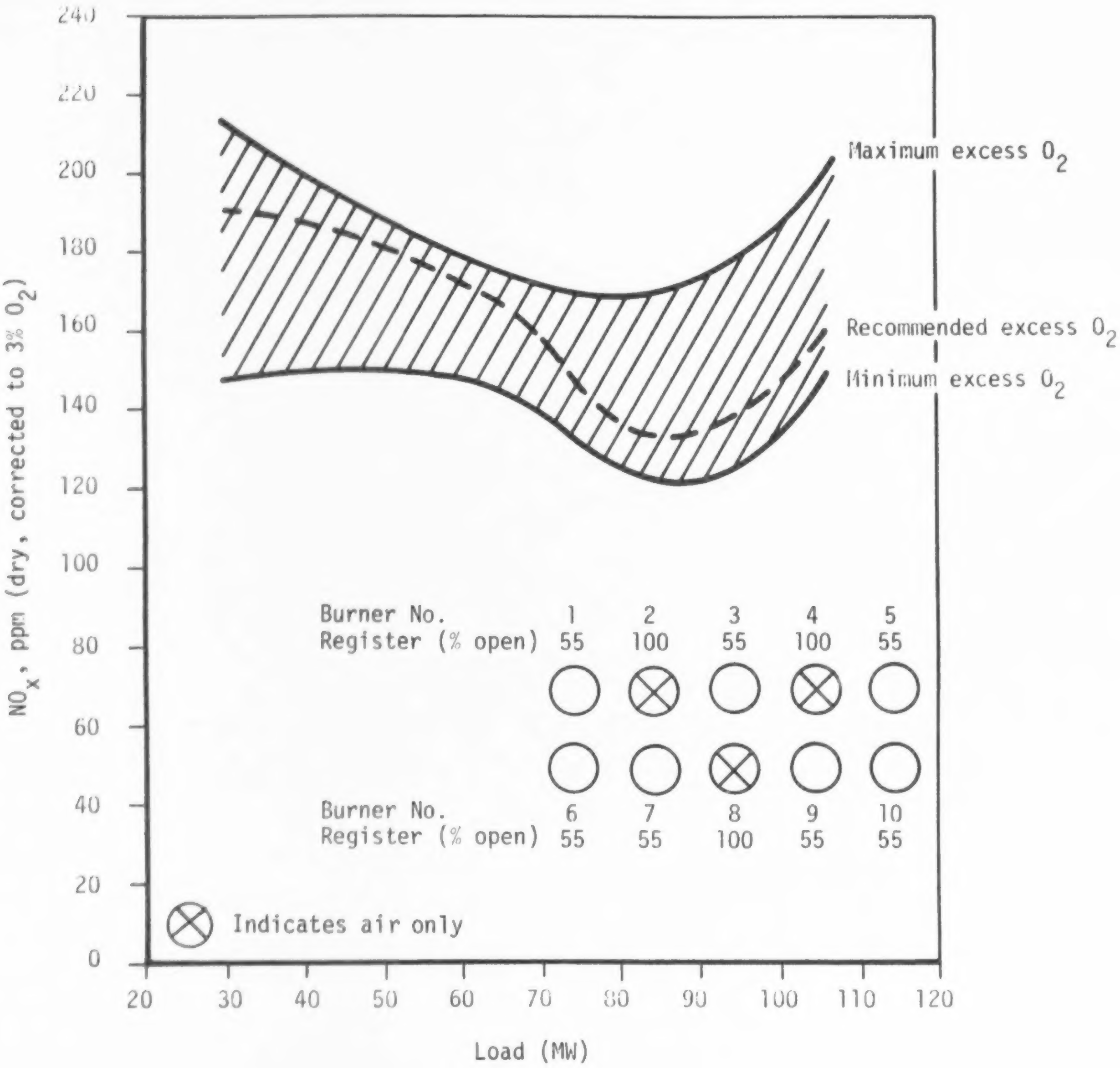
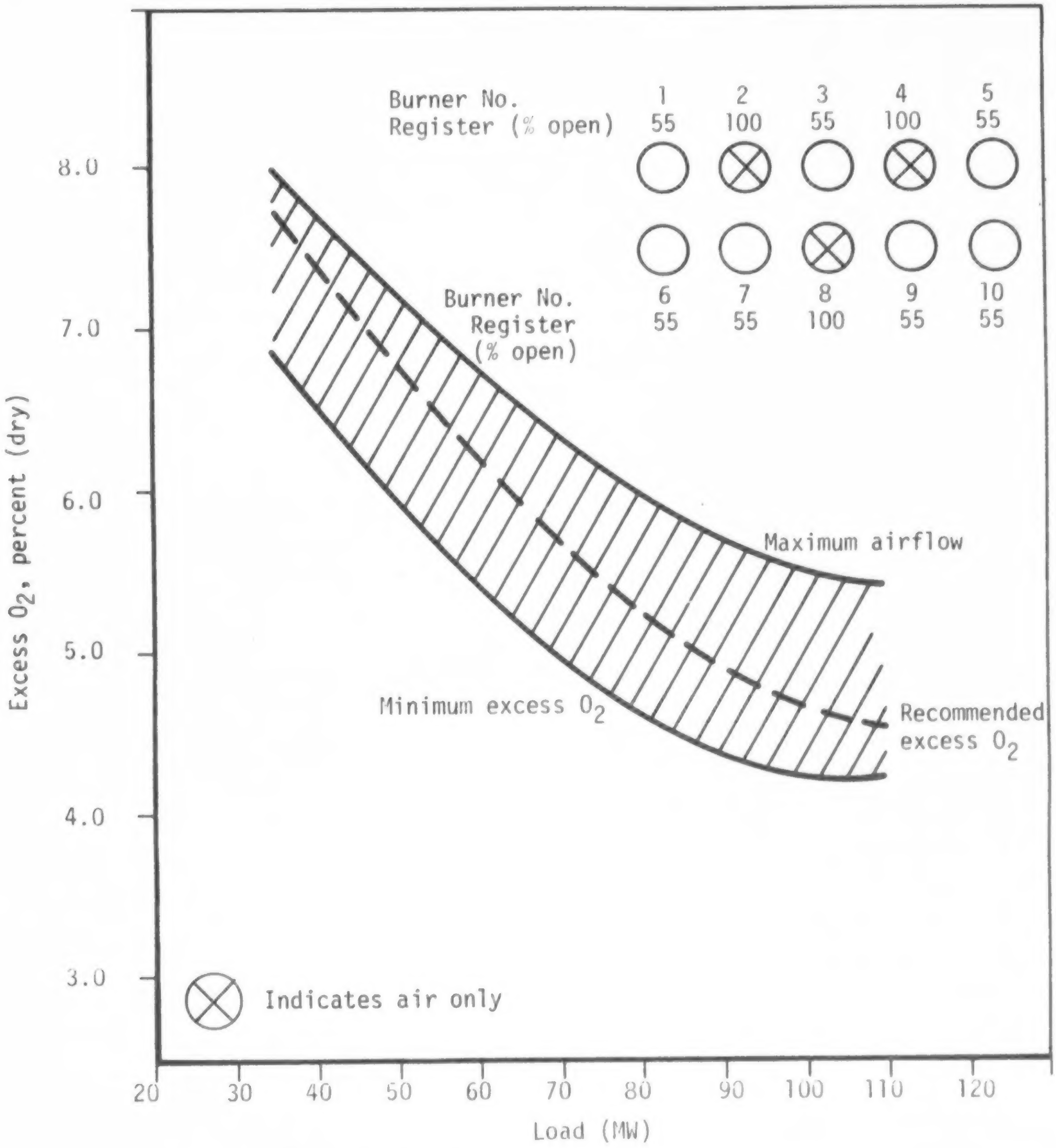


Figure 6-10. NO$_x$ emissions for oil fuel with seven-burner operation for Encina Unit No. 1 (Reference 6-13).



*As read in control room

Figure 6-11. Operating excess O_2 curve for Encina Unit No. 1 for oil fuel with seven-burner operation (Reference 6-13).

three-BOOS operation are much higher than the levels of O_2 with two-BOOS or normal operation, especially at higher load levels. This is due to the increased tendency for the boilers to smoke as the degree of off stoichiometric firing is increased. The Encina Unit No. 1 is atypical, however, in that all registers have a common swirl direction in the lower row of burners. This causes the flame to turn upwards and cling to the furnace wall instead of protruding into the furnace. This flame pattern caused local smoking which cleared only when excess air was increased. The other two Encina units have alternating swirl directions which apparently cause the flames to protrude into the furnace. Those two units can therefore operate with lower excess air levels (about 2 to 4 percent at 100 MW) than Encina No. 1. Nevertheless, they still require higher excess O_2 levels than with normal or two-BOOS operation.

Peak load tests for Encina No. 1 showed that with an excess O_2 level of 4.5 percent the maximum turbine load was 100 MW. Lowering the O_2 level to 3.9 percent allowed the maximum turbine load to increase to 103 MW. Thus a 1 percent increase in O_2 level decreased the unit's capacity by 5 MW. As mentioned earlier, this is mainly due to the boiler being airflow limited at full load. An increase in excess air levels, therefore, translates to a smaller fuel flow for the same airflow rate, thus reducing boiler capacity. In general, it was found that for all the three boilers, a derate of up to 5 MW could be expected with three-BOOS operation.

Table 6-16 shows a comparison of some process variables when Unit No. 1 was operated with two and three burners out of service. In contrast to the data for two-BOOS operation shown in Table 6-15, the data in Table 6-16 for two-BOOS operation show that the superheater temperature reached the normal level of 811K (1000°F). This was due to the increased excess O_2 level for the two-BOOS operation in Table 6-16. It was found that for normal and two-BOOS operation increasing excess air levels always increased steam temperatures. Surprisingly, however, with three-BOOS operation increasing excess air levels decreased steam temperatures. In Table 6-16 the SH steam temperature for three-BOOS operation is 800K (980°F) at 3.8 to 4.0 percent O_2 (below the recommended O_2 range). Increasing the excess O_2 level will further decrease the SH temperature. Lower steam temperatures generally result in lower cycle efficiency. However, a comparison of cycle efficiency has not been attempted here due to possible

TABLE 6-16. COMPARISON OF ENCINA UNIT NO. 1 OPERATED WITH TWO AND THREE BURNERS OUT OF SERVICE (Reference 6-13)

Process Variables		Two-BOOS Operation	Three-BOOS Operation
Load	MW	99.8	99.8
Control Room O_2	Percent	3.3 to 3.5	3.8 to 4.0
Burners Out of Service		Nos. 2 & 4	Nos. 2, 4, & 8
SH Steam Temp.	K ($^{\circ}$F)	811 (1000)	800 (980)
RH Steam Temp.	K ($^{\circ}$F)	808 (995)	800 (980)
Steam Flow	kg/s (10^3 lb/hr)	81.9 (650)	81.0 (643)
Oil Flow	kg/s (10^3 lb/hr)	7.5 (59.5)	7.3 (58)
Indicated Airflow	(Meter Setting)	54	52
Attemperator Temp. In	K ($^{\circ}$F) N	689 (780)	678 (760)
	S	675 (755)	672 (750)
Attemperator Temp. Out	K ($^{\circ}$F) N	680 (765)	678 (760)
	S	675 (755)	678 (760)
Furnace Draft	kPa (inch H_2O)	-0.11 (-0.45)	-0.11 (-0.45)
AH Gas In	K ($^{\circ}$F) N	633 (680)	622 (660)
	S	633 (680)	630 (675)
AH Gas Out	K ($^{\circ}$F) N	433 (320)	433 (320)
	S	425 (305)	422 (300)
Ringleman Smoke Chart No.		0.41	0.45
Measured NO_x	ppm N	206	145
	S	174	115
Measured CO	ppm N	0	0
	S	0	0

variations in the fuel oils used in the tests listed in Table 6-16. In all other respects there is no significant difference in the process variables between two-BOOS and three-BOOS operation.

It should be noted that the various test conditions for Encina Unit No. 1, as discussed in this section, do not necessarily reflect current operating practice. The utility has been active in maintaining low NO_x emissions and improving boiler efficiency with different firing configurations and burners (Reference 6-20).

In summary, front wall oil-fired boilers, at least of the type studied here, show no significant deterioration with BOOS operation. With increased off stoichiometric firing some derating may occur, but the extent of derating is generally small. Higher excess O_2 levels will probably be associated with increased staging and some loss in efficiency may be expected. From a boiler operator's point of view, the major change will be in flame patterns and increased tendency to smoke. Careful inspection of the furnace and convective tubes would be recommended at periodic intervals, but again no major problems would be anticipated.

6.9 TURBO FURNACE OIL-FIRED BOILERS

A series of tests for NO_x reduction were carried out on South Bay Boiler No. 3 operated by San Diego Gas and Electric Company (Reference 6-8). The boiler is a 12 burner turbo fired Riley Stoker unit with a maximum continuous steam flow rating of 145 kg/s (11.5×10^5 lb/hr). Before any combustion modifications were undertaken, the flow of air between the two windboxes was balanced. Pitot tubes were installed in the individual burner compartments. The splitter vane which divides the airflow to the two windboxes was then adjusted to ensure even air distribution as measured by the pitot readings.

The velocity dampers and the directional vanes at the individual burners were next optimized for low NO_x operation. It was found that velocity dampers had little effect on NO_x emissions. Still, the optimum position was found to be the normal position of from 60 to 80 percent open for both top and bottom dampers. NO_x levels were however, sensitive to directional vanes positions. By raising both the upper and lower vanes up by 30^0 with respect to the direction of the fuel guns, NO_x reductions by 40 to 50 ppm were achieved. These NO_x reductions were apparently due to an overfire air effect caused by directing the airflow 30 degrees above the direction of fuel flow.

The first two columns of Table 6-17 show a comparison of some process data for the boiler operated at partial load under normal and modified airflow conditions. Except for the reduction in NO_x, there is very little change in the process variables.

Although the modified airflow conditions reduced NO_x emissions, the reductions were not sufficient to meet statutory requirements especially at higher loads. Water injection was then tried as a NO_x reduction technique. Water was introduced into the heated combustion air as a fine mist by means of a bank of spray nozzles. Reductions in NO_x emissions up to 50 percent of baseline at maximum load were obtained. Water injection tests with water to fuel loadings of up to 1.016 kg H_2O/kg oil were carried out without any flame instability problems encountered. Steam and tube temperatures were only slightly affected. However, oil consumption increased by as much as 6 percent at full loads. The last two columns in Table 6-17 give some process data for the unit operated at partial load under different water injection rates. NO_x emissions decreased substantially with water injection. Note that the unit load decreased with water injection for approximately constant fuel flowrate. Figure 6-12 shows the variation of NO_x emissions over the boiler load range under baseline, modified airflow, and water injection conditions. The water injection was increased with load as shown in the figure to maintain NO_x levels within the regulation limits under all load conditions without excessive performance losses. Due to the increased fuel consumption associated with water injection, this control technique was considered as an interim measure by SDG&E until OFA ports could be installed and tested.

Another NO_x control technique tested on this unit was Reduced Air Preheat (RAP). Combustion air temperature was lowered by bypassing the preheater. NO_x reductions of 40 to 70 ppm per 56K (100^oF) reduction in air temperature at 75 and 100 percent of full load, respectively, were obtained. It was found, however, that to achieve the same NO_x reduction, water injection was more cost-effective than RAP due to lower boiler efficiency losses. RAP was, therefore, not recommended as a NO_x control technique for this unit.

TABLE 6-17. COMPARISON OF SOUTH BAY UNIT NO. 3 AT PARTIAL UNDER BASELINE AND LOW NO_x OPERATION ON OIL FUEL UNDER PARTIAL LOAD (Reference 6-8)

Process Variables		Baseline	Airflow Adjustment	Water Injection	
Load	MW	138	138.5	133	131.5
Excess Oxygen	%	5.4	4.8	4.5	4.8
Steam Flow	kg/s (10^5lb/hr)	119 (9.5)	121 (9.6)	111 (8.8)	110 (8.7)
Fuel Oil Flow	kg/s (10^3lb/hr)	7.9 (63)	8.0 (63.5)	8.1 (64)	8.1 (64)
Water Injection:					
Flowrate	kg/s (10^3lb/hr)	0	0	3.72 (29.5)	6.05 (48.0)
Water/Fuel Ratio	kg/kg	0	0	0.461	0.750
Velocity Dampers					
Top	% open	75	75	77	77
Bottom	% open	75	75	77	77
Directional Vanes					
Upper	degree	0	up 30	up 30	up 30
Lower	degree	0	up 30	up 30	up 30
Burner Air Dampers	% open	100	100	100	100
Pressures:					
Steam Drum	MPa (psi)	14.4 (2090)	14.4 (2090)	14.2 (2055)	14.1 (2050)
Burner Supply	MPa (psi)	4.86 (705)	4.90 (7.10)	4.76 (690)	4.76 (690)
Burner Return	MPa (psi)	2.59 (375)	2.59 (375)	3.31 (480)	3.34 (485)
Windbox	kPa (in H_2O)	2.3 (9.2)	2.2 (9.0)	2.3 (9.4)	2.4 (9.6)
Furnace	kPa (in H_2O)	1.5 (6.1)	1.4 (5.5)	1.9 (7.5)	1.9 (7.8)
Temperatures:					
SH Steam	K (^{o}F)	811 (1001)	810 (999)	806 (992)	806 (992)
RH Steam	K (^{o}F)	811 (1001)	802 (985)	796 (974)	809 (997)
Oil Supply	K (^{o}F)	372 (210)	372 (210)	368 (204)	368 (203)
AH Air In	K (^{o}F)	297 (76)	298 (77)	298 (77)	297 (76)
AH Air Out	K (^{o}F)	580 (585)	578 (582)	422 (300)	<422 (<300)
AH Gas In	K (^{o}F)	655 (720)	655 (720)	646 (703)	652 (715)
AH Gas Out	K (^{o}F)	408 (275)	407 (273)	399 (260)	402 (265)
F.D. Fan Current	Amps	156	160	165	164
Emissions:					
NO_x (at 3% O_2)	ppm	267	229	162	143
CO	ppm	0	0	0	0
Ringleman Smoke Density	ppm	0	0	0	0

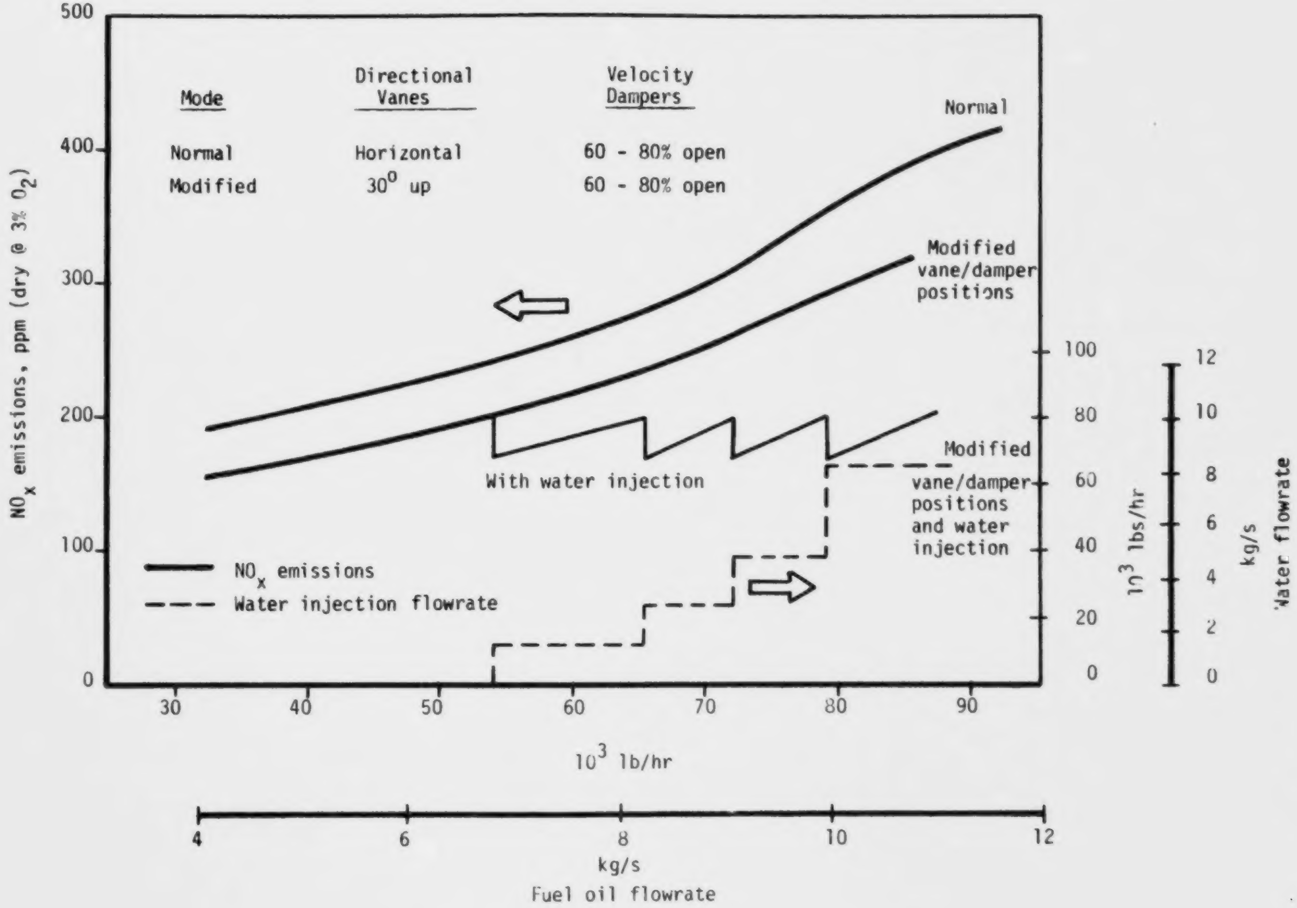


Figure 6-12. Characteristic NO$_x$ emissions on oil fuel from South Bay Unit No. 3 (Reference 6-8).

Pacific Gas and Electric Company has also modified its Riley Stoker Potrero Boiler 3-1 for NO_x reduction (Reference 6-9). This boiler is capable of generating 189 kg/s (1.5×10^6 lb/hr) of steam. The hardware modification on the boiler included installation of OFA ports designed to handle up to 25 percent of combustion air. An FGR system was also retrofitted to the unit. Windbox oxygen content could be diluted to 17 percent with FGR. In addition some reheater surface was removed and a new and larger fin tube economizer was installed as part of the modifications.

Baseline NO_x emissions for the Potrero Unit 3-1 were approximately 350 ppm at full load. Low NO_x operation (OFA + FGR) of the boiler reduced the emissions down to about 250 ppm. Some tests were carried out with OFA alone, but it was found that stack smoking occurred with the OFA ports opened only a small amount. The tendency to smoke required that the boiler be operated with a minimum of 4 percent excess O_2 under normal low NO_x operation (OFA + FGR). The high excess air requirements combined with increased convective transfer due to FGR and altered flue gas temperature profiles due to OFA caused tube metal and steam temperature limits to be approached. During a period of time the boiler experienced one superheater tube failure per month. The boiler was curtailed to 95 percent of full load and removed from automatic dispatch operation due to unacceptable temperature excursions at high loads. Due to the addition of economizer surface to this boiler, the boiler efficiency was expected to improve despite the higher excess air requirements.

In summary, traditional NO_x control techniques such as FGR and OSC have been successful in reducing NO_x emissions from oil-fired turbo furnace boilers. Moderate amounts of NO_x reduction can be obtained by experimenting with velocity dampers and directional vanes to achieve an overfire air effect. In addition, substantial reduction in NO_x emissions can possibly be obtained by the use of OFA ports above the throat to create a precombustion fuel-rich zone in the lower portion of the furnace. However, this may be accompanied by an increased tendency towards smoking. Higher oxygen levels required to eliminate smoke may in turn lead to higher superheater and reheater tube and steam temperatures. These temperatures are usually increased by FGR and OFA operation, so that an increase in excess air requirements may cause an exacerbation of the problem. Finally, water injection can be used to control NO_x emissions from oil-fired boilers. There is, however, a penalty associated with this type of low NO_x operation in reduced boiler efficiency and consequently higher fuel costs per unit of electrical energy generated. Water injection may be useful as a temporary measure to control NO_x emissions until major hardware modifications such as FGR and OFA can be retrofitted.

6.10 TANGENTIAL GAS-FIRED BOILERS

Process data on tangential gas-fired boilers closely resemble that on tangential oil-fired boilers as most such units are designed to accept both oil and gas fuels depending upon availability. Many tangential units have low baseline NO_x emissions due to the nature of combustion in tangential furnaces. For these units simple modifications such as low excess air operation are often sufficient to reduce NO_x emissions to meet statutory requirements. In other cases, where baseline NO_x emissions are much higher than the desired levels, the usual NO_x reduction techniques used with gas and oil such as flue gas recirculation (FGR) and off stoichiometric combustion (OSC) have been employed.

A comparison of process data on South Bay Boiler No. 4 under baseline and low NO_x operation is shown in Table 6-18 (Reference 6-8). The unit is a 230 MW Combustion Engineering tangentially fired cycling boiler, with a straight-through furnace, capable of generating 198 kg/s (1.57×10^6 lb/hr) of steam. The boiler is operated by San Diego Gas and Electric Company. The unit had always required higher operating excess oxygen levels than the design values due to a tendency for high carbon monoxide generation. Stack traverse data showed large local carbon monoxide concentrations in one portion of the stack. Due to the straight-through design of the boiler, there is little mixing of the gases from the furnace to the stack so that high local CO levels in one portion of the stack reflect high CO generation in a corresponding section of the furnace. It was found that the airflow to the burners was maldistributed. Uniform distribution was achieved by closing the auxiliary air dampers, but instead of closing the dampers fully, they were left open by 10 percent to cool and purge the auxiliary air compartment. The fuel air dampers were left fully open. Better distribution of air resulted in a lowering of minimum excess air levels, which consequently led to a decrease in NO_x emissions. The

TABLE 6-18. COMPARISON OF SOUTH BAY UNIT NO. 4 OPERATED UNDER BASELINE AND LOW NO_x CONDITIONS UNDER PARTIAL LOAD (Reference 6-8)

Process Variables		Baseline	Low Excess Air	OSC Operation
Load	MW	176	182.5	178.5
Excess Oxygen	Percent	3.8	1.3	3.3
Burners Out of Service		None	None	2 from top tier
Burner Tilt	Degrees	-14	-18	-18
Flowrates:				
Steam	kg/s (10^6 lb/hr)	145 (1.15)	153 (1.21)	151 (1.20)
Natural Gas	nm^3/hr (10^6 scfh)	4.8 (169)	5.0 (175)	5.0 (175)
Temperatures:				
SH Steam	K (^oF)	775 (935)	784 (951)	783 (950)
RH Steam	K (^oF)	769 (925)	785 (953)	784 (952)
AH Air Out	K (^oF)	384 (231)	380 (225)	383 (229)
Stack Gas	K (^oF)	636 (685)	628 (670)	630 (675)
Pressures:				
Steam Drum	MPa (psi)	12.3 (1790)	11.2 (1630)	11.1 (1610)
Natural Gas at Burner	MPa (psi)	0.110 (16.0)	0.116 (16.8)	0.155 (22.5)
Furnace	kPa (inch H_2O)	1.0 (4.0)	0.85 (3.4)	1.0 (4.0)
Windbox/Furnace Differential	kPa (inch H_2O)	1.0 (4.0)	2.2 (8.8)	>2.5 (>10)
FD Fans:				
Discharge Pressure	kPa (inch H_2O)	3.31 (13.3)	4.06 (16.3)	4.70 (18.9)
Current	Amps	302	302	320
Fuel Air Damper	Percent open	100	100	100
Auxiliary Air Damper	Percent closed	0	90	90
Emissions:				
NO_x (at 3% O_2)	ppm	119	97	106
CO	ppm	7	145	4
Ringleman Smoke Density		0	0	0

lowered throughput in the furnace also reduced stack losses as indicated by lower stack gas temperatures and lower fuel consumption. These effects are shown for the range of boiler loads in Figures 6-13 and 6-14. The first two columns in Table 6-18 also give some process data at partial loads for the boiler operated under normal conditions (with nonuniform air distribution) and low excess air conditions (with uniform air distribution).

The boiler was also tested with some burners on air only. The furnace has three levels of burners. The results of taking two burners out of service from opposite corners of the topmost tier are shown in the last column of Table 6-18. It is seen that although the dampers are positioned for uniform air distribution, the excess air level was higher than the minimum value obtained with low excess air operation. The NO_x level was also higher than that obtained with LEA operation. However, some tests at reduced load (around 140 MW) showed that NO_x emissions could be reduced down to about 70 ppm with all burners in the top tier on air only. The minimum excess oxygen level under these conditions was approximately 3.5 percent; any further reduction caused excessive carbon monoxide emissions. OSC operation was not recommended for this boiler as LEA firing was capable of reducing NO_x emissions to values below the regulatory requirements, and because OSC operation resulted in higher required excess oxygen levels, with associated loss in efficiency.

Pacific Gas and Electric Company has modified its Combustion Engineering, tangentially fired, 675 kg/s (5.36×10^6 lb/hr) of steam, Pittsburg No. 7 Boiler for low NO_x operation (Reference 6-9). The modifications involved installing OFA ports, capable of injecting 20 percent of total air, and introducing FGR to the windbox capable of reducing oxygen in the combustion air down to 17 percent. PG&E encountered a number of problems with low NO_x operation of this boiler. The baseline NO_x emissions of this unit at full load amounted to approximately 750 ppm which is relatively high for a boiler of this type. The amount of flue gas recirculation required to reduce the NO_x emissions to the local limit of 175 ppm caused excessive reheat steam temperatures and subsequent load curtailment. These high rates of FGR combined with OSC operation often led to high convective section tube and steam temperatures. FGR increased mass flowrates, the increased velocities giving rise to higher heat transfer coefficients.

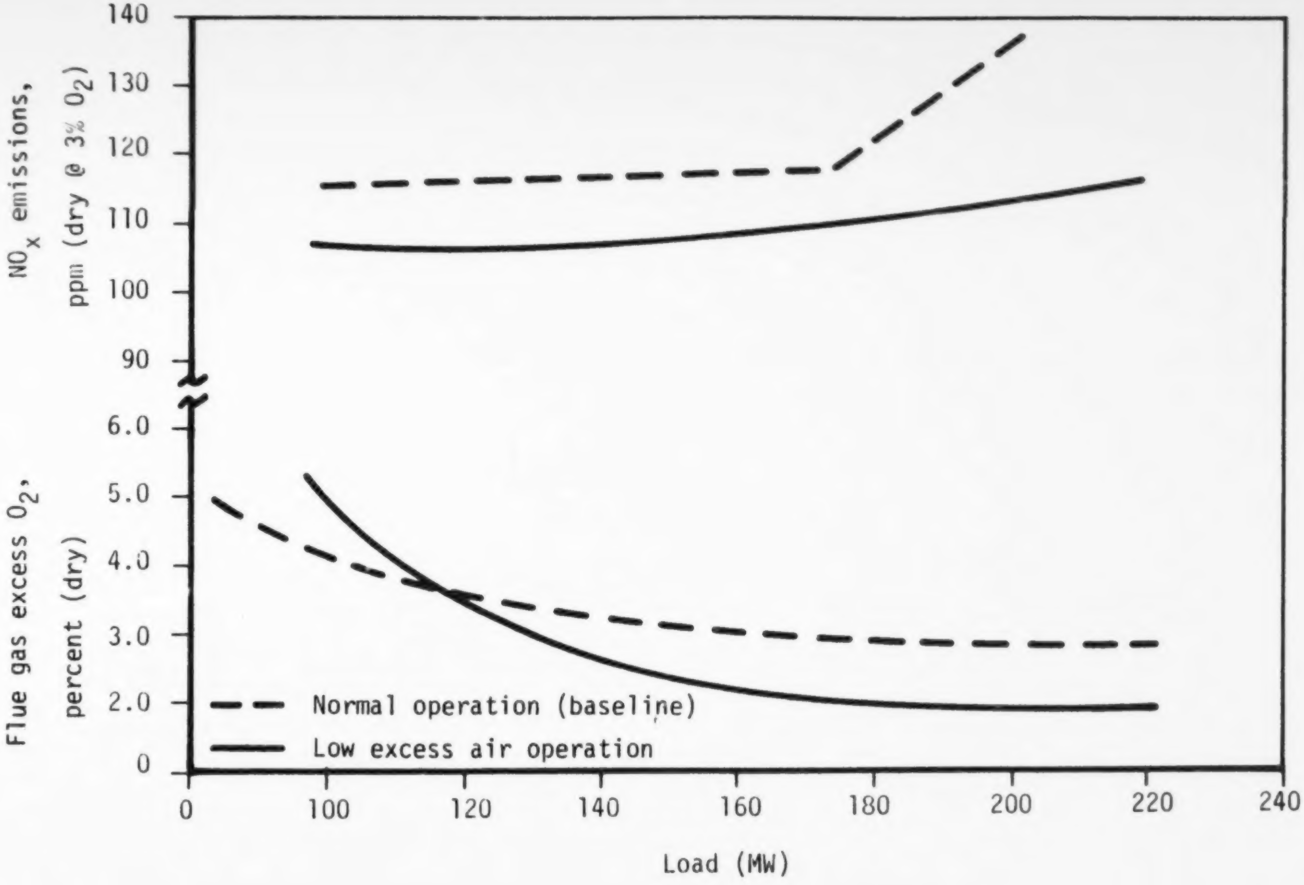


Figure 6-13. Comparison of NO_x emissions and minimum excess oxygen levels under baseline and low excess air conditions for South Bay Unit No. 4 (Reference 6-8).

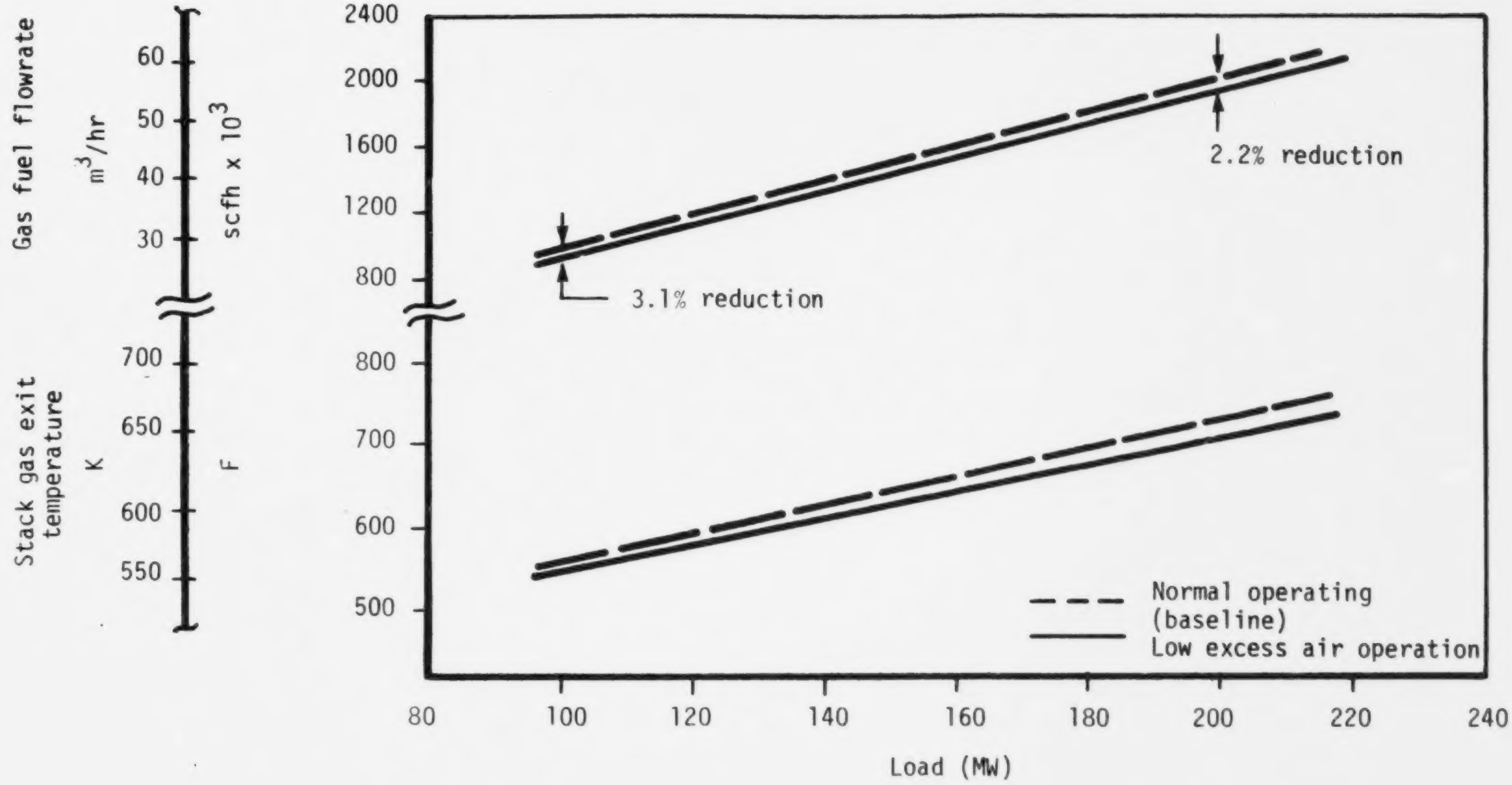


Figure 6-14. Comparison of gas consumption and stack temperature under baseline and low excess air conditions for South Bay Unit No. 4 (Reference 6-8).

Staging resulted in a lengthened combustion zone which increased the furnace outlet gas temperatures. This phenomenon is common in gas-fired units with small furnaces where the combustion zone fills the entire furnace. In some cases the heat transfer rates and temperatures may be high enough to cause tube failures or excessive steam temperatures which exceed steam desuperheater capacities. In such cases boiler derating may be required. In the case of the Pittsburg No. 7 Boiler, maximum load capacity was reduced by 25 percent. The load curtailment on Pittsburg No. 7 has recently been overcome by removing the capability of circulating flue gas through the furnace hopper. In other cases, where a significant amount of reheat attemperation is required, a loss in cycle efficiency will result.

Some other adverse effects caused by low NO_x operation at the Pittsburg No. 7 Boiler were: fan, duct, and building vibrations, high water wall panel outlet tube temperatures, and reduction in load change response.

In summary, tangential gas-fired boilers can be modified for NO_x reduction using traditional NO_x control techniques. In cases where the baseline emissions are not much higher than the desired levels, simple techniques such as low excess air operation may be used. Excess air levels can be minimized by ensuring uniform fuel/air distribution at the burners. In cases where baseline emissions are high, FGR, OSC, or a combination of the two may be required. In some cases, adverse effects such as vibrations, high tube and steam temperatures, and reduced load response capability will be encountered. In certain cases, especially with small furnaces and high volumetric heat release rates, boiler derating may occur. For new boilers with larger furnaces and factory- equipped OFA systems, there should be no adverse effects associated with low NO_x operation.

6.11 HORIZONTALLY OPPOSED GAS-FIRED BOILERS

Very little process data are available on horizontally opposed gas-fired boilers. However, boilers are often designed to accept both gas and oil fuels. Thus, much of Section 6.7 on horizontally opposed oil-fired boilers would also be pertinent here, especially the details concerning hardware and control modifications which are essentially similar for oil- and gas-fired boilers.

Pacific Gas and Electric Company has reported its experience with converting six of its horizontally opposed boilers to low NO_x operation (References 6-9 and 6-14). The Moss Landing Boilers Nos. 6 and 7 were the first among PG&E boilers to be modified for reduction of NO_x emissions. These boilers were manufactured by Babcock and Wilcox Company, have 48 burners each divided into four levels, and can produce up to 640 kg/s (5.1×10^6 lb/hr) of steam. The baseline NO_x emissions on these boilers averaged over 1400 ppm at full load. Various techniques were tried to reduce NO_x levels. The only techniques which resulted in the substantial reductions desired were off stoichiometric firing, by taking the top level of burners out of service and a combination of flue gas recirculation and off stoichiometric firing. OSC firing alone gave NO_x reductions of 81 percent. OSC combined with FGR resulted in a reduction in NO_x of 94 percent from baseline.

Table 6-19 gives a comparison of process data for the Moss Landing Boiler No. 7 when operated under OSC and a combination of OSC with various degrees of FGR to windbox (Reference 6-11). Unfortunately, no corresponding baseline data were available with matching operating conditions. It is seen that the power requirements of the FGR fan increase substantially as the amount of FGR to the windbox is increased. At about 7 percent FGR to the windbox the fan power increased by approximately 10 percent over that required for FGR to the hopper. When FGR to the windbox was increased to 19 percent, the fan power requirements increased by 66 percent. The furnace pressure also increased as FGR to the windbox increased due to the higher furnace mass flowrate. The original furnace trip, which was set at 5.2 kPa (21 inch H_2O), had to be raised to 6.0 kPa (24 inch H_2O) under low NO_x operation. This is very close to the boiler maximum design pressure of 6.7 kPa (27 inch H_2O).

At high rates of FGR to windbox, attemperation of reheat system was required. This was partly due to the increased mass flowrates which tended to increase heat transfer coefficients in the convective section. Under normal operating procedure, reheat steam spray attemperation is generally avoided due to associated cycle efficiency losses. Typically under baseline operation of these boilers, superheat and reheat steam temperatures are controlled by a combination of flue gas recirculation to the hopper, proportioning dampers and spray attemperation. With FGR directed to the windbox for NO_x control, it could no longer be employed to control steam temperatures. Some limitations on damper control were also encountered due to the high furnace pressures.

TABLE 6-19. COMPARISON OF MOSS LANDING BOILER NO. 7 UNDER OFF STOICHIOMETRIC COMBUSTION AND COMBINED OFF STOICHIOMETRIC COMBUSTION AND FLUE GAS RECIRCULATION (Reference 6-11)

Process Variables		BOOS Operation	BOOS + 7 Percent FGR to Windbox	BOOS + 14 Percent FGR to Windbox	BOOS + 19 Percent FGR to Windbox
Load	MW	733	734	734	733
Burhner Firing Pattern		Upper row BOOS	Upper row BOOS	Upper row BOOS	Upper row BOOS
Gas Recirculation to Windbox	Percent	0.0	6.9	13.8	19.0
O_2 in Windbox	Percent	21.0	19.8	18.8	18.1
Overall Excess O_2	Percent	1.6	1.8	1.7	1.9
Mean Steam Flow	kg/s (10^6 lb/hr)	655 (5.20)	649 (5.15)	649 (5.15)	649 (5.15)
SH Attemp. Spray Flow	kg/s (10^3 lb/hr)	19 (150)	24.4 (194)	21.8 (173)	16.0 (127)
RH Attemp. Spray Flow	kg/s (10^3 lb/hr)	0	0	0	9.7 (77)
SH Steam Pressure	MPa (psig)	25.7 (3720)	25.7 (3720)	25.7 (3720)	25.7 (3720)
RH Steam Pressure	MPa (psig)	4.4 (630)	4.4 (630)	4.4 (630)	4.4 (630)
SH Steam Temperature	K (°F)	806 (992)	808 (994)	808 (995)	805 (990)
RH Steam Temperature	K (°F)	810 (999)	811 (1000)	810 (999)	811 (1000)
Furnace Pressure	kPa (inch H_2O)	5.15 (20.7)	5.23 (21.0)	5.85 (23.5)	5.77 (23.2)
Air Heater Temperatures:					
Air In	K (°F)	299 (79)	300 (80)	300 (80)	299 (79)
Air Out	K (°F)	564 (555)	565 (558)	574 (574)	574 (573)
Gas In	K (°F)	625 (666)	628 (671)	635 (684)	633 (680)
Gas Out	K (°F)	400 (260)	401 (262)	403 (266)	402 (266)
Flue Gas Recirculation:					
Fan Current Consumption	Amps	106	116	138	176
GR to Air Foil	Percent	0	100	100	100
GR to Hopper	Percent	100	0	0	0
NO_x (3% O_2 base)	ppm	223	148	103	73
CO	ppm	178	196	55	28

From Table 6-19 it is seen that when FGR is increased to 19 percent, about 10 kg/s (80,000 lb/hr) of reheat spray flow was required. PG&E has estimated that this results in a 0.8 percent loss in cycle efficiency. Removing some reheater surface would overcome this problem, but was not attempted in this case because it would have resulted in even higher efficiency losses when the boilers switched to oil fuel.

It should be noted that the data in Table 6-19 were taken under clean boiler conditions. With gas fuels NO_x emissions are very sensitive to boiler wall conditions. This poses a significant problem in boilers which alternate between oil and gas fuels. In the Moss Landing Boiler the NO_x emissions standards of 125 ppm could not be met when switching back to gas fuel after a few days of oil burning, even though the ash content of the fuel oils used was only about 0.02 percent by weight. Only a complete water washing of the furnace and convective passes after each period of oil burning could resolve the problem, but this solution was considered impractical when frequent switching was required. Switching from oil to gas also caused problems of high reheat and superheat temperatures as the higher furnace exit gas temperatures associated with low NO_x operation were further exacerbated by decreased heat absorption in a dirty furnace. In some of the horizontally opposed PG&E boilers the reheat spray water limit was approached on gas fuel after only nominal oil firing. Furthermore, in some boilers the superheater tube temperature limit of 850K (1070^oF) was being closely approached and required close monitoring. One boiler was curtailed to about 50 percent of full load when switching back to gas fuel due to superheater tube temperature limits being exceeded. A series of upper wall tube failures have occurred in that boiler. Also, some boilers have been operating near the furnace pressure limit with FGR, aggravated by slagging after periods of oil burning.

The baseline NO_x emissions at full load from the Moss Landing Boilers, as mentioned earlier, averaged over 1400 ppm. The baseline emissions at full load of the other horizontally opposed boilers reported in Reference 6-9 ranged from about 770 ppm for the Pittsburg Boilers Nos. 5 and 6 to approximately 425 ppm for the Contra Costa Boilers Nos. 9 and 10. The Pittsburg and Contra Costa Boilers produce 272 kg/s (2.16 x 10^6 lb/hr) of steam as compared to the rated capacity of 640 kg/s (5.1 x 10^6 lb/hr) for the Moss Landing Boilers. All boilers were modified in a similar manner for

NO_x control. All were retrofitted to allow FGR to the windbox. In cases where FGR to the hopper existed for steam temperature control, the FGR fans were replaced with larger fans. In others where no FGR capability existed, new fans were installed. In all boilers the FGR systems were capable of diluting the oxygen in the windbox to 17 percent. In the Moss Landing Boilers, OSC operation was carried out by injecting as much as 17 percent of the total air through the top row of burners (BOOS). In the other boilers OFA ports were retrofitted to allow up to 20 percent of the total air to be introduced through the ports. In all cases the techniques of combined OSC and FGR were effective in reducing NO_x levels down to around 125 to 175 ppm when the boilers were clean. Although the baseline NO_x emissions from these boilers span a wide range indicating a wide range of flame intensities and surface heat rates, the problems encountered in low NO_x operation of the boilers were remarkably similar. As mentioned earlier, higher convective section and upper furnace temperatures resulted due to higher furnace exit gas temperatures and increased heat transfer coefficients. Furnace exit gas temperatures usually rose with staged firing, as combustion in this mode takes place over a larger part of the furnace, and in some cases filled the whole furnace. Heat absorption profiles may no longer peak in the lower half of the furnace and the gas temperature profiles change accordingly. Convective heat transfer coefficients increase due to the higher mass flowrates through the boiler with FGR. The higher mass flowrates have also resulted in duct and furnace vibrations, flame instability problems, and high furnace pressures. The furnace vibration and flame instability problems were resolved in some cases by installing new gas spuds and flame retainers especially developed for this purpose. Duct vibration problems required reinforcement of the FGR ducts and installation of splitter vanes. Higher furnace pressures have necessitated raising the furnace trip settings, in some cases very close to the upper design limit of the furnace.

In summary, horizontally opposed gas-fired boilers can be successfully modified for low NO_x operation even in cases where the baseline emissions are quite high. A combination of OSC and FGR operation has resulted in maximum NO_x reduction. As is the case with other types of boiler design, the NO_x reductions attainable will be generally less and not continuously attainable for boilers utilizing both gas and oil fuels. A number of problems have been associated with these modifications. High reheat, superheat, and upper furnace wall temperatures have occurred, which may result in increased tube failure. Flame instabilities, boiler vibration and high furnace pressures are other potential adverse effects experienced with OSC + FGR firing. High tube and steam temperatures may be particularly troublesome in boilers which switch between oil and gas firing. Losses in cycle efficiency up to 1 percent have occurred if reheat steam required attemperation. No derating of boilers was reported, but is possible in cases where furnace pressure limits, tube temperature limits, or maximum attemperation capacities are exceeded. No data were available on boiler efficiency. However, as minimum excess air requirements have not been reported to increase with low NO_x operation on gas-fired boilers, the boiler efficiencies are not expected to be affected.

6.12 SINGLE WALL GAS-FIRED BOILERS

The 100 MW, San Diego Gas and Electric Company, Encina Units No. 1, 2, and 3 discussed in Section 6.8 were also tested for low NO_x operation with natural gas fuel (Reference 6-13). The reduction in NO_x emissions for gas fuel were also carried out in two steps. The first was designed to meet the 1971 San Diego APCD regulation of 225 ppm NO_x for natural gas-fired utility boilers. The second step was to reduce NO_x levels to 125 ppm to meet 1974 standards.

The 1971 standards were met by combustion modification similar to those used for oil firing. The boilers were fired off stoichiometrically by taking 2 burners out of service from a total of 10. Fuel flow was terminated to burner Nos. 2 and 4 in the top row of burners and the air registers on these burners were opened 100 percent. Of the remaining burners there were indications that the four wing burners received less air than others. In order to attain uniform air distribution to the active burners, the wing burner registers were opened 100 percent and the rest of the active burner registers were throttled down to 70 percent open. A sketch of the burner and register configurations are shown at the bottom of Figure 6-15.

Taking two burners out of service necessitated an increase in gas flow to the active burners to maintain maximum load. This was achieved by increasing the gas delivery pressure through raising the gas pressure regulator setting at each unit. This was not expected to create any adverse

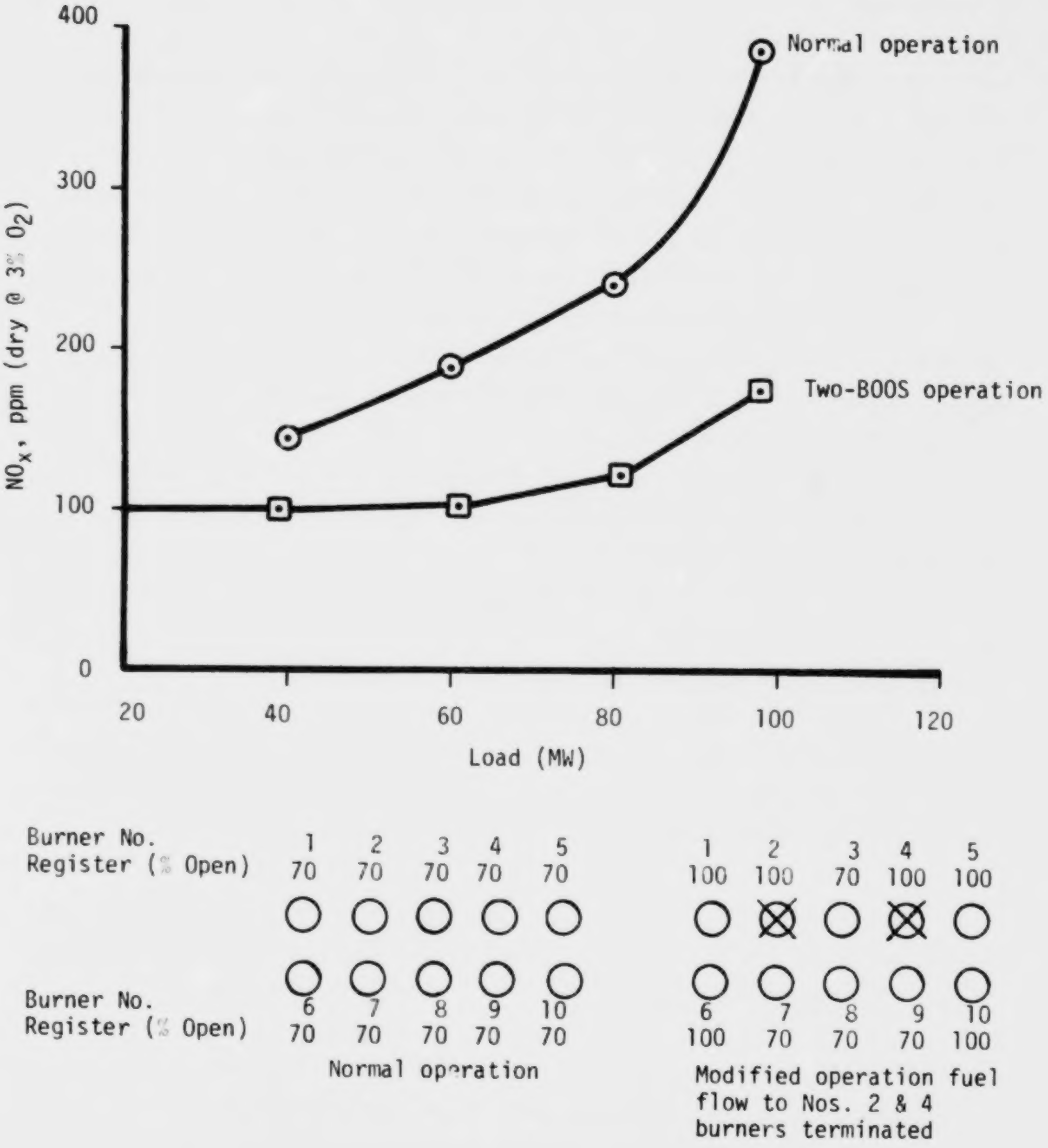


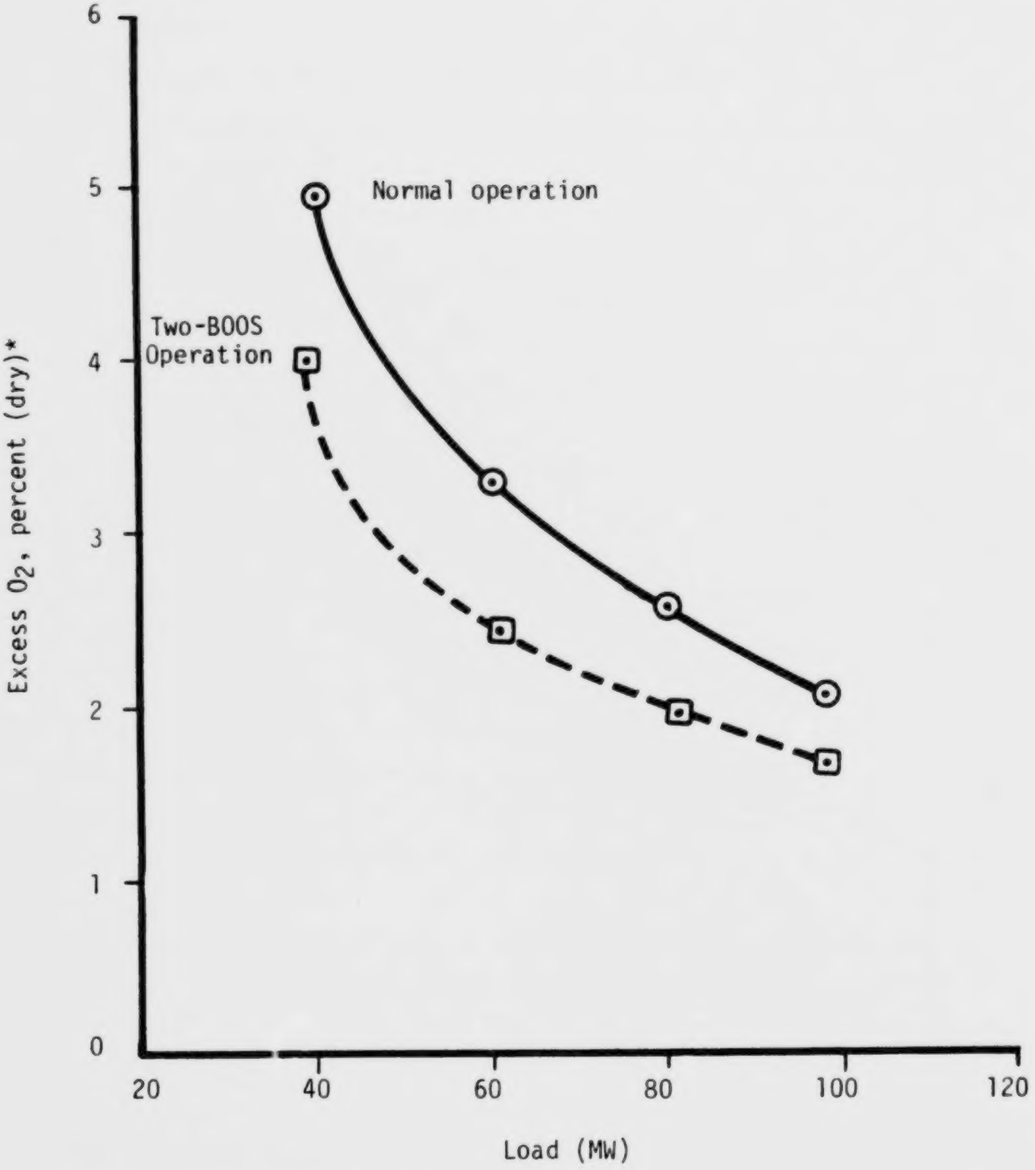
Figure 6-15. Comparison of NO$_x$ with normal and two-BOOS operation with natural gas fuel for Encina Unit No. 1 (Reference 6-13).

effect on boiler operation. On one of the boilers some load pickup tests were carried out. It was found that combustion modification did not in any way affect unit response.

A number of tests were carried out to establish the minimum excess air levels under low NO_x operation which would ensure that carbon monoxide levels would not exceed 100 ppm. Curves for excess oxygen levels as a function of load were drawn up for each boiler. In general, the recommended levels were conservative as the corresponding CO levels had a maximum value of 30 ppm. Even so, the recommended curves for excess O_2 under low NO_x operation fell below the excess O_2 curves for normal (baseline) operation. Figure 6-16 gives the excess O_2 curves under normal and low NO_x operation for the Encina No. 1 Boiler. The corresponding NO_x levels are shown in Figure 6-17.

Table 6-20 gives a comparison of some process variables under baseline and operation with two burners out of service. There were no major changes except for an increased imbalance between the north and south ducts under two-BOOS operation. This imbalance was noted on this boiler only and was attributed to plugging of holes on the burner rings. No other major problems were encountered. There was some flame carryover to the superheater sections but it did not result in problems with high tube temperatures or tube wastage. Increased attention to ring burners, tube walls, and convective tubes was recommended for the low NO_x operation. These could be readily incorporated in the normal furnace maintenance program.

The 1974 NO_x regulations (125 ppm) were met by taking three burners out of service. The burner pattern which best reduced NO_x emissions was slightly different from two-BOOS operation with oil firing for this unit. The burner pattern and register settings which gave optimum results are shown at the bottom of Figure 6-17. As with two-BOOS operation, tests were run to establish recommended excess O_2 levels as a function of load. The results are shown in Figure 6-18 for the Encina No. 1 Boiler. The recommended excess O_2 levels were not much different from two-BOOS operation for this unit. The same is true for the other units. The Encina units are largely airflow limited. An increase in excess air level, therefore, generally leads to a reduction in maximum load. However, as the excess air requirements do not increase with OSC operation in these units



*As read in control room

Figure 6-16. Comparison of excess O_2 for normal and two-BOOS operation with natural gas fuel for Encina Unit No. 1 (Reference 6-13).

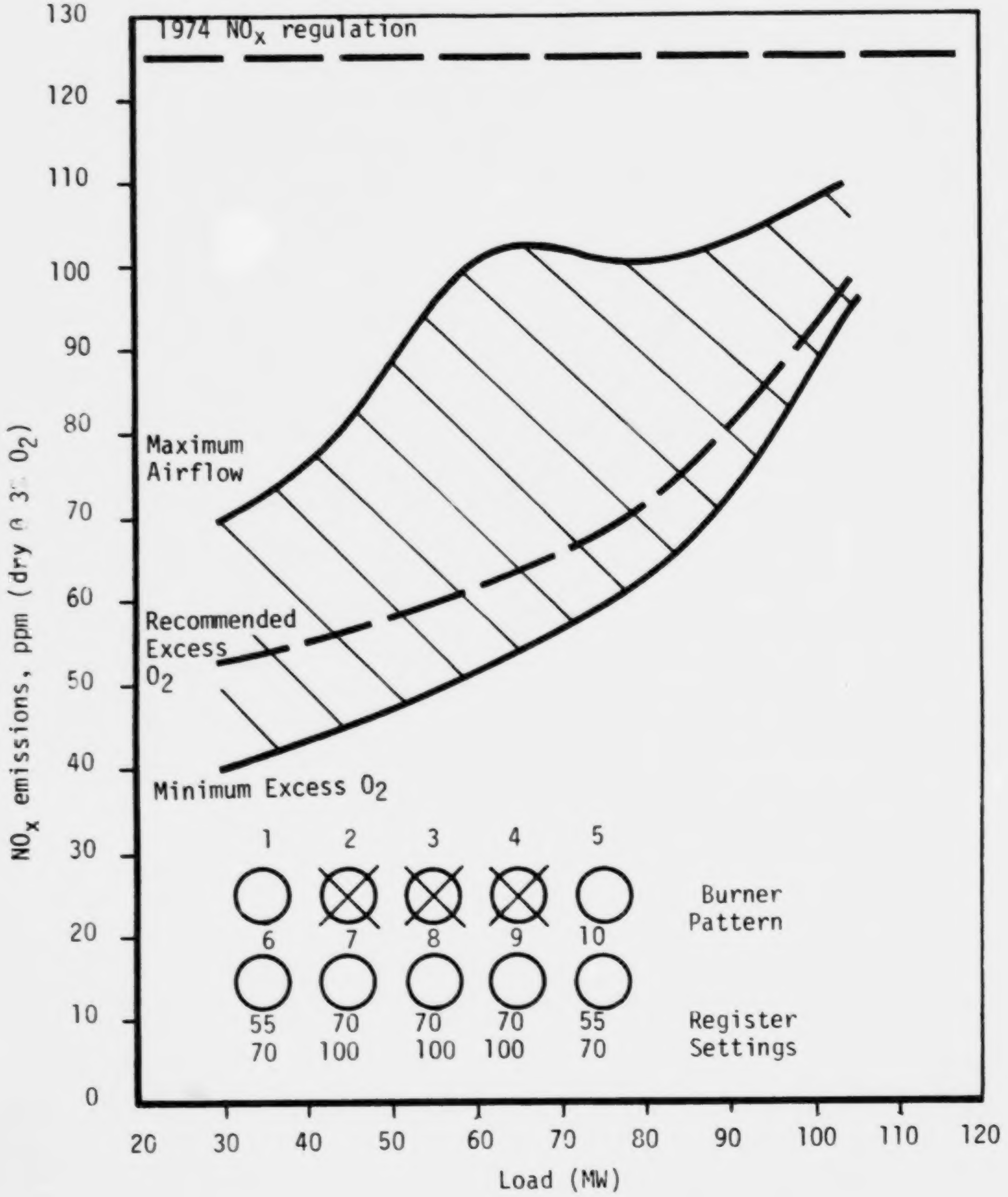
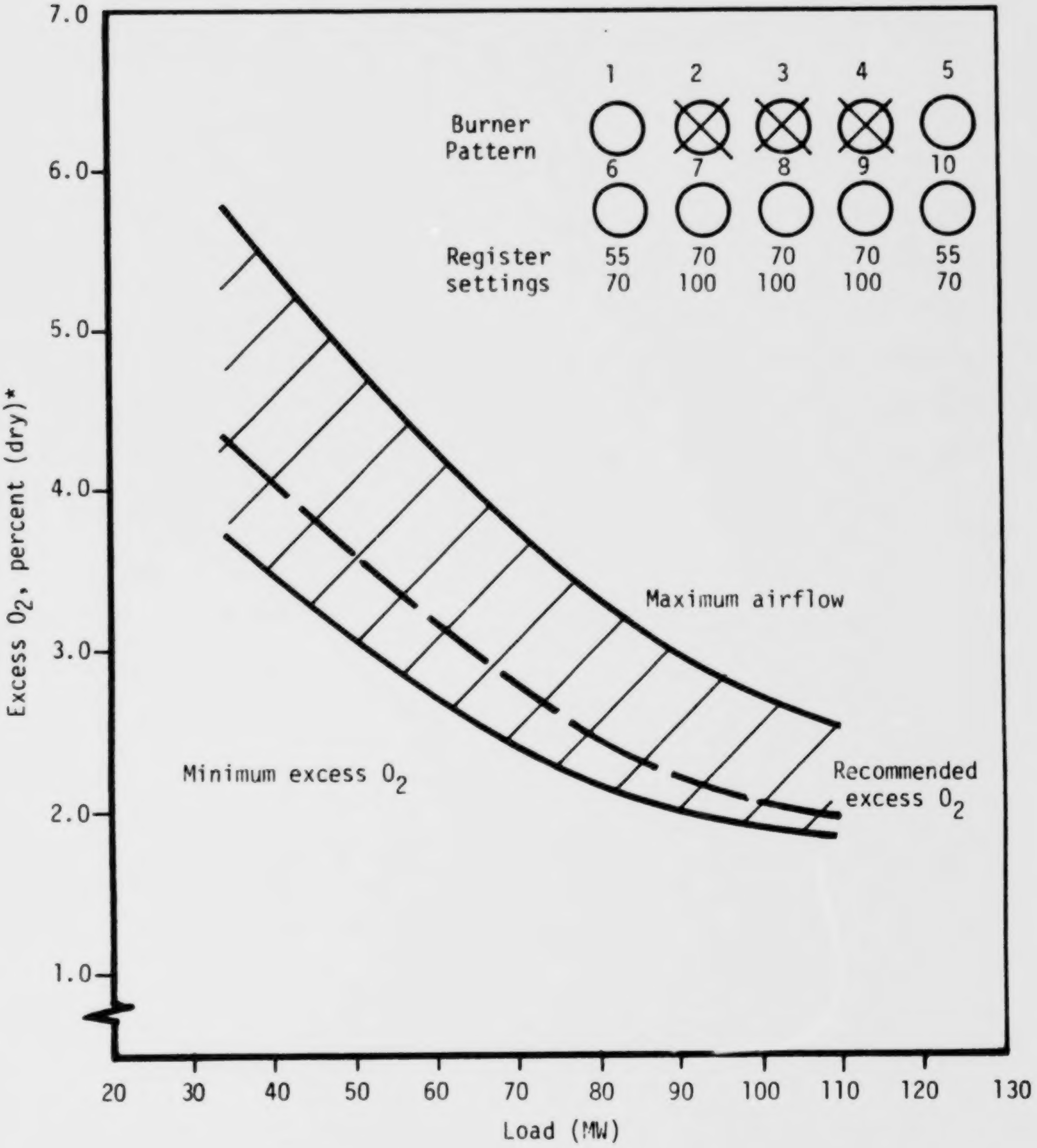


Figure 6-17. NO_x emissions versus load for gas fuel with seven-burner operation for Encina Unit No. 1 (Reference 6-13).

TABLE 6-20. COMPARISON OF GAS-FIRED ENCINA UNIT NO. 1, OPERATED UNDER BASELINE CONDITIONS AND WITH TWO BURNERS OUT OF SERVICE (Reference 6-13)

Process Variables			Baseline Operation	Two-BOOS Operation
Load	MW		98	98
Control Room O_2	Percent		2.0 to 2.2	1.6 to 1.8
Burners Out of Service			None	Nos. 2 & 4
Steam Temperature	K (°F)		811 (1000)	811 (1000)
Indicated Gas Flow	(Meter setting, arbitrary units)		920/1100	860/1100
Indicated Airflow			58/70	58/70
Supply Gas Pressure	MPa (psi)		0.160 (23.0)	0.186 (27.0)
Burner Gas Pressure	MPa (psi)		0.076 (11.0)	0.125 (18.1)
Furnace Draft Pressure	kPa (inch H_2O)		-0.1 (-0.5)	-0.1 (-0.5)
AH Gas Out Temperature	K (°F)	N	453 (355)	455 (360)
		S	450 (350)	444 (340)
AH Gas in Temperature	K (°F)	N	653 (715)	658 (725)
		S	650 (710)	650 (710)
RC Fan	Amps		0	0
FD Fan	Amps	N	80	80
		S	80	81
ID Fan	Amps	N	115	106
		S	115	108
Measured NO_x	ppm	N	320	150
		S	375	160
Measured CO	ppm	N	30	40
		S	30	50



*As read in control room

Figure 6-18. Operating excess O_2 curve for natural gas fuel with seven-burner operation for Encina Unit No. 1 (Reference 6-13).

when fired with gas, no derating of the units was needed. The NO_x emissions from Encina No. 1, corresponding to the excess O_2 levels given in Figure 6-18, are shown in Figure 6-17.

Table 6-21 gives a comparison of some process variables for the Encina No. 1 Boiler under two-BOOS and three-BOOS operation. No major changes in the variables were experienced as the degree of off stoichiometric firing was increased. Table 6-21 does not, however, represent normal boiler operation as the tests were conducted prior to a major overhaul including servicing and cleanup. The No. 2 air register was not functioning properly before the overhaul. Thus, Table 6-21 should not be compared directly with Table 6-20.

As three-BOOS operation with natural gas involved operating with the three center top burners out of service, the boiler performance changed in terms of the effect of excess air on final steam temperatures. Increasing overall excess air tended to reduce steam temperatures, in contrast with usual practice where increasing airflow results in higher steam temperatures. Apparently, this was due to the cooling effect of the air from the BOOS ports in the superheater and reheater. However, no problems with maintaining steam temperatures at design levels were anticipated, as OSC operation with gas fuel did not lead to higher excess air requirements.

The Encina units have provisions for flue gas recirculation to maintain adequate transfer coefficients in the convective sections. It was found that FGR was not required above 80 MW with three-BOOS operation compared to about 90 MW with two-BOOS operation. At high loads with OSC firing some pressure pulsing occurred in the corners of the firebox even though the furnace probe indicated a stable negative furnace pressure. This was attributed to irregularities in the bulk gas flow dynamics, and it was recommended that care be exercised when opening the observation ports on the operating level. No other adverse effects were observed. The boiler efficiency was not notably affected by OSC operation. In summary, the data indicates that no significant operational or maintenance problems are likely to occur with OSC operation of front wall gas-fired boilers of the type studied here.

6.13 TURBO FURNACE GAS-FIRED BOILERS

A limited amount of process data are available on gas-fired turbo furnace boilers. In general, the available NO_x control techniques for

TABLE 6-21. COMPARISON OF GAS-FIRED ENCINA UNIT NO. 1, OPERATED WITH TWO AND THREE BURNERS OUT OF SERVICE PRIOR TO OVERHAUL (Reference 6-13).

Process Variables			Two-BOOS Operation	Three-BOOS Operation
Load	MW		100	100.8
Control Room O_2	Percent		2.2 to 2.6	2.5 to 3.5
Burners Out of Service			Nos. 2 & 4	Nos. 2, 3, & 4
SH Steam Temperature	K (^{o}F)		811 (1000)	811 (1000)
RH Steam Temperature	K (^{o}F)		803 (985)	816 (1010)
Steam Flow	kg/s (10^3 lb/hr)		88.5 (702)	90.1 (715)
Indicated Gas Flow	(Meter settings, arbitrary units)		950	940 to 980
Indicated Airflow			60	64
Attemperator Temp. In	K (^{o}F)	N	685 (775)	694 (790)
		S	678 (760)	686 (775)
Attemperator Temp. Out	K (^{o}F)	N	647 (705)	672 (750)
		S	672 (750)	675 (755)
Furnace Draft	kPa (inch H_2O)		-0.13 (-0.54)	-0.05 (-0.2)
Flue Gas Recirculation			Off	Off
AH Gas In	K (^{o}F)	N	625 (665)	669 (745)
		S	639 (690)	655 (720)
AH Gas Out	K (^{o}F)	N	439 (330)	455 (360)
		S	442 (335)	450 (350)
Ringleman Smoke Chart No.			0.34	0.4
Measured NO_x	ppm	N	220	111
		S	207	125
Measured CO	ppm	N	0	0
		S	0	0

these boilers are the same as for oil-fired turbo furnaces. The NO_x control techniques for which process data are available on turbo furnaces include OFA, FGR, airflow adjustment, reduced air preheat, and water injection.

South Bay Unit No. 3, a Riley Stoker turbo furnace unit owned by San Diego Gas and Electric Company, was tested extensively for reductions in NO_x emissions (Reference 6-8). The boiler can be fired with both oil and gas, has 12 burners, and has a maximum continuous rating of 145 kg/s (11.5×10^5 lb/hr) of steam. After balancing the airflow to each of the two windboxes, the settings on the velocity dampers and directional vanes were varied to reduce NO_x emissions. It was found that minimum NO_x emissions were obtained when the velocity dampers on the part of the burner below the fuel guns were completely closed and the velocity dampers above the fuel guns were fully open. Apparently this arrangement simulated an overfire air effect. The NO_x emissions were further decreased when the directional vanes above the fuel guns were directed upwards at an angle of 30 degrees or higher relative to the direction of fuel injection as was the case for oil firing. The first two columns in Table 6-22 show a comparison of some process data with the boiler at partial load under baseline and adjusted airflow conditions. It is seen that a substantial reduction in NO_x emissions occurs under the adjusted airflow conditions, although part of the reduction may be attributed to the slightly lower air preheat temperature and excess oxygen level. The excess oxygen in the adjusted airflow test was reduced to a minimal level as can be gauged by the higher carbon monoxide generation and plume smoking condition.

Although a significant decrease in NO_x emissions occurred by adjusting damper and vane settings, the reduction was not sufficient to meet statutory limits especially at higher loads. Consequently, water injection by means of a bank of nozzles into the preheated combustion air was tested as a NO_x control measure. The results of water injection for two different injection rates are shown in the last two columns of Table 6-22 for partial load. The results of the NO_x control techniques, viz., airflow adjustment and water injection, are shown in Figure 6-19 for the whole range of boiler loads. The amount of water required to maintain NO_x emissions below the legal limit is also shown as a function of load. The increasing amount of water injection with load decreases the boiler

TABLE 6-22. COMPARISON OF GAS-FIRED SOUTH BAY UNIT NO. 3 UNDER BASELINE AND LOW NO_x CONDITIONS UNDER PARTIAL LOAD (Reference 6-8)

Process Variables		Baseline	Airflow Adjustment	Water Injection	
Load	MW	137	132	134	129
Excess Oxygen	%	1.6	1.2	3.6	3.4
Steam Flow	kg/s (10^5 lb/hr)	113 (9.0)	107 (8.5)	109 (8.65)	108 (8.6)
Natural Gas Flow	nm^3/s (10^5 scfh)	9.75 (12.4)	9.91 (12.6)	9.83 (12.5)	9.75 (12.4)
Water Injection:					
Flowrate	kg/s (10^3lb/hr)	0	0	3.65 (29.0)	5.86 (46.5)
Water/Fuel Ratio	kg/kg	0	0	0.508	0.821
Velocity Dampers					
Top	% open	70	100	100	100
Bottom	% open	70	0	0	0
Directional Vanes					
Upper	degree	0	up 45	up 45	up 45
Lower	degree	0	0	0	0
Pressures:					
Steam drum	MPa (psi)	14.9 (2160)	14.7 (2130)	14.2 (2060)	14.0 (2025)
Burner Natural Gas	MPa (psi)	0.086 (0.5)	0.083 (12.0)	0.083 (12.1)	0.083 (12.1)
Windbox	kPa (in. H_2O)	1.6 (6.5)	1.6 (6.6)	2.3 (9.1)	0.9 (3.8)
Furnace	kPa (in. H_2O)	1.2 (5.0)	1.0 (4.1)	1.8 (7.3)	1.8 (7.3)
Temperatures:					
SH Steam	K (°F)	810 (999)	807 (994)	809 (997)	809 (997)
RH Steam	K (°F)	798 (978)	807 (994)	806 (991)	814 (1007)
AH Air In	K (°F)	296 (73)	296 (73)	297 (75)	297 (76)
AH Air Out	K (°F)	569 (565)	541 (515)	436 (325)	429 (313)
AH Gas In	K (°F)	638 (690)	624 (665)	648 (708)	655 (720)
AH Gas Out	K (°F)	408 (275)	391 (245)	405 (270)	408 (275)
F.D. Fan Current	Amps	122	122	150	
Emissions:					
NO_x (at 3% O_2)	ppm	238	187	135	98
CO	ppm	30	100	10	102
Ringleman Smoke Density	ppm	0	0 (Slight plume)	0	0

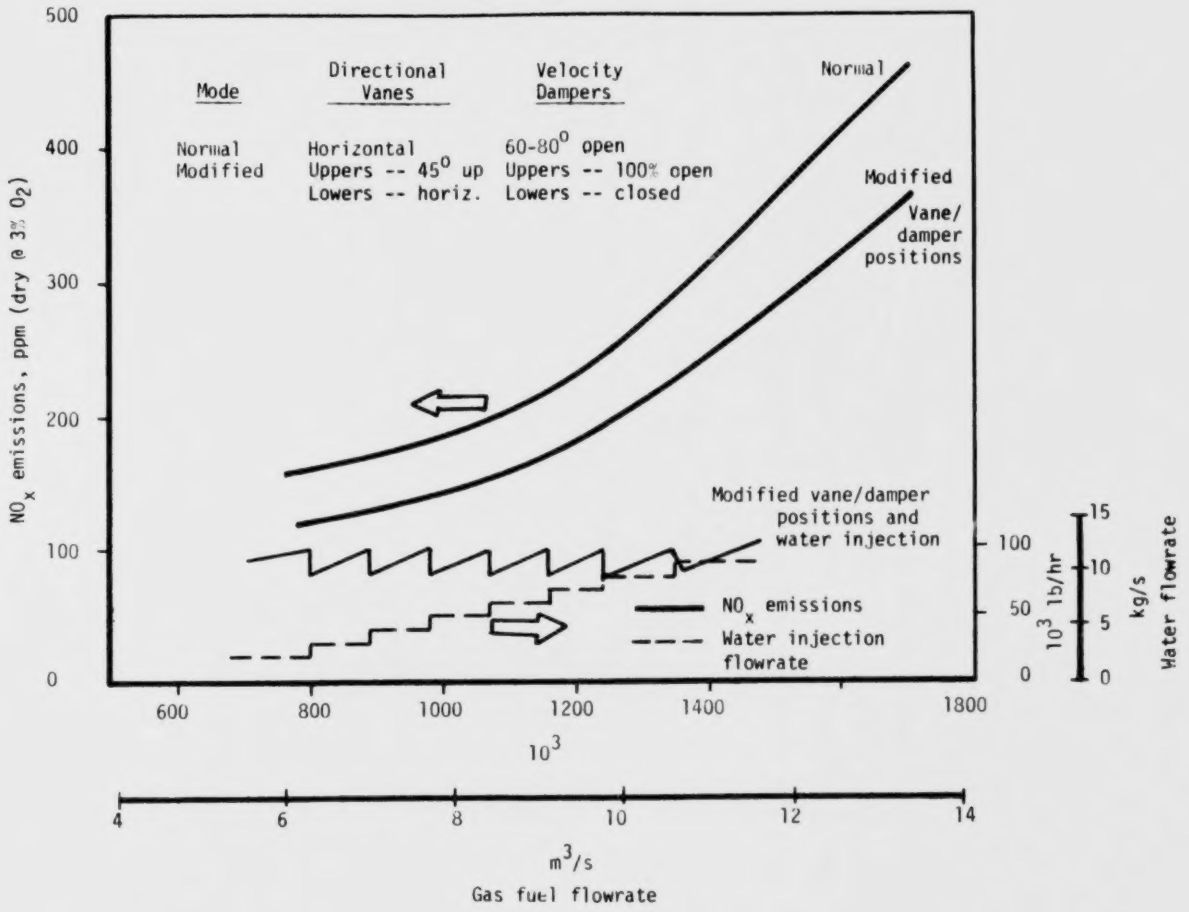


Figure 6-19. NO$_x$ emissions for gas-fired South Bay Unit No. 3 (Reference 6-8).

efficiency, necessitating an approximately 10 percent increase in fuel consumption at full load. However, no flame stability problems were encountered even with water to fuel ratios as high as 1.3 by weight.

Water injection reduces NO_x emissions, at least partially, by decreasing the combustion air temperature. The decrease in combustion air temperature with increasing water injection rates can be seen in Table 6-22. Some tests were also carried out with reduced air preheat by bypassing some of the air and gas flow in the air heater. It was found that the effect on NO_x emissions due to a decrease in combustion air temperature using air heater bypass was similar to that obtained by water injection with the same decrease in temperature. With oil fuels, however, it was found that water injection was much more effective than air heater bypass. For this reason, water injection was recommended over RAP by air heater bypass for this boiler. Water injection, however, is considered only to be an interim NO_x control measure until low NO_x techniques which result in less severe boiler performance penalties, such as OFA, can be installed.

Pacific Gas and Electric Company has also reported NO_x reduction modifications to its turbo furnace Potrero Boiler NO. 3-1 (Reference 6-9). This boiler is a turbo furnace capable of burning both oil and gas and generating 189 kg/s (1.5×10^6 lb/hr) of steam. The furnace was retrofitted with OFA ports designed to handle up to 25 percent of the combustion air and FGR capable of reducing windbox oxygen content to 17 percent. Convective section modifications were also made to compensate for the change in absorption profiles incurred with FGR and OFA. Part of the reheater surface was removed in order to avoid excessive reheat steam attemperation, and the economizer was replaced by a larger fin tube economizer to improve the efficiency of the unit.

The baseline NO_x emissions at full load for Potrero No. 3-1 amounted to approximately 530 ppm. The use of OFA alone resulted in a reduction of 50 percent in NO_x emissions. Operation with OFA and FGR reduced NO_x levels down to approximately 175 ppm. Some problems, however, arose with combined OFA and FGR operation. Tube metal and steam temperature limits were approached at high loads resulting in increased superheater tube failures as noted above for oil firing. Boiler load was limited to 95 percent of full rated value and the unit was removed from automatic dispatch operation due to the problems with superheater temperatures at high loads.

In summary, the usual NO_x control techniques used with gas fuels such as OFA and FGR were successful in controlling NO_x emissions from turbo furnace boilers. These techniques may, however, be associated with problems such as high convective section temperatures. Due to the flexibility in controlling the airflow at the burners inherent in the turbo furnace design, the airflow may be adjusted to create an overfire air effect. This may in some cases result in significant NO_x reductions. Water injection and reduced air preheat were also successful in reducing NO_x emissions. However, the high increased fuel consumption penalty associated with these techniques make them unattractive except as an interim NO_x control measure.

6.14 SUMMARY OF PROCESS ANALYSES

A summary of the impact of low NO_x operation on boiler operation and performance is given in this section. Details of process analyses for each combination of furnace/fuel type have been discussed in the preceding sections. There were some furnace/fuel combinations, however, where there were insufficient data to allow for an adequate treatment of all applicable low NO_x techniques. This section attempts to integrate the data on various boilers by considering each fuel type separately regardless of furnace type. Thus, the major NO_x control techniques used for each fuel and the effects of low NO_x operation on the boiler are discussed below.

It should be noted that the various test conditions discussed in the preceding sections do not necessarily reflect current operating procedures for any one specific boiler. Generally, utilities are continuously seeking ways of increasing boiler efficiencies while achieving low emissions.

6.14.1 Coal-Fired Boilers

The effects of low NO_x operation on coal-fired boilers are summarized in Table 6-23. The most commonly applied low NO_x techniques for coal-fired boilers are low excess air (LEA) and off stoichiometric combustion (OSC). Low NO_x burners are also being installed on some new units and have been found to be effective. Other techniques which have been tested but are less commonly employed are flue gas recirculation (FGR), which has been found to be relatively ineffective, and water injection (WI), which is not preferred because of efficiency losses. The major concerns

TABLE 6-23. EFFECT OF LOW NO_x OPERATION ON COAL-FIRED BOILERS

Boiler	Low NO_x Technique	Efficiency	Corrosion	Load Capacity	Carbon Loss in Flyash	Dust Loading[a]	Part. Size Distribution[a]	Other Effects, Comments
Tangential								
Barry No. 2	BOOS	Unaffected	Measured 75% increase, but within normal range	20% derate	Slight increase	100% increase	--[a]	Minor changes in heat absorption profile SH attemperation increase by 70%
	OFA	Unaffected	Measured 70% increase, but within normal range	Unaffected	Slight increase	100% increase	--	Minor changes in heat absorption profile SH attemperation increased over 200%
Columbia No. 1	OFA	Unaffected	No change	Unaffected	Slight increase	--[a]	--	Minor changes in heat absorption profile SH attemperation increased by 70%
Huntington Canyon No. 2	OFA	Unaffected	Measured 25% decrease, but within normal range	Unaffected	Slight increase	--	--	Minor changes in heat absorption profile No SH attemperation required
Barry No. 4	LEA, BOOS	Unaffected	No significant change	20% or more derate with BOOS	50% average decrease	50 average increase	--	
Navajo No. 2	LEA, BOOS, OFA	Unaffected	No significant change	Unaffected	No change	40% average increase	No change	
Commanche No. 1	OFA	Unaffected	No significant change	Unaffected	30% average decrease	20% average decrease	No significant change	
Opposed Wall								
Harllee Branch No. 3	LEA, BOOS	0.6% average decrease	Slight increase	Up to 17% derate with BOOS	130% average increase	10% average increase	--	
Four Corners No. 4	LEA, BOOS Water injection	0.6% increase (excluding WI)	No significant change	Up to 25% derate with BOOS	50% average decrease	15% average decrease	--	
Hatfield No. 3	BOOS	0.3% decrease	--[a]	10% derate	30% average increase	Unaffected	--	No slagging or fouling. No significant increase in tube temperatures. Increase in POMs by 30%.
	FGR	0.4% decrease in boiler efficiency. Some decrease in cycle efficiency due to RH attemperation.	--	Unaffected	120% average increase	Unaffected	--	Stable flames and uniform combustion. Increase in RH attemperation. No increase in POM emissions. No significant increase in tube temperatures.

[a] Denotes that investigated

TABLE 6-23. Concluded

Boiler	Low NO_x Technique	Efficiency	Corrosion	Load Capacity	Carbon Loss in Flyash	Dust Loading[a]	Part. Size Distribution[a]	Other Effects, Comments
E.C. Gaston No. 1	LNB, LEA, BOOS	0.3% decrease on average (LNB baseline)	No significant increase	Up to 30% derate (LNB with BOOS)	130% average increase (LNB baseline)	15% average increase (LNB baseline)	Shift towards smaller particles (LNB, with or without BOOS)	Unit retrofitted with low NO_x Baseline, LEA and BOOS tests with LNB compared to baseline tests on sister boiler with no LNB.
FW Unit A	BOOS	Unaffected	--	Up to 25% derate	85% increase	--	--	Severe slagging and hazy flames filling furnace at burner stoichiometries below 95%
Single Wall								
Widows Creek No. 5 (TVA test)	BOOS	1% increase	Results of tests inconclusive	Unaffected	30% increase	No significant increase	--[a]	
Widows Creek No. 5 (Exxon test)	LEAS, BOOS	1% average increase	No significant increase	Unaffected	30% average decrease	15% average decrease	--	
Widows Creek No. 6	LEA, BOOS	Unaffected	--	Unaffected	70% average increase	20% average decrease	--	
Mercer Station No. 1 (wet bottom)	LEA, Biased firing	Unaffected	No significant increase	Unaffected	80% average increase	10% average increase	No significant change	
Crist Station No. 6	LEA, BOOS	0.4% decrease	--	Up to 15% derate	60% increase	50% increase	--	
FW Unit B	BOOS	--	--	25% derate	Unaffected	--	--	Severe slagging and hazy but stable flames at burner stoichiometries below 95%
FW Unit C	OFA	Unaffected	--	Unaffected	Unaffected	--	--	NSPS unit with larger fire box and factory installed OFA ports. No problems with slagging reported.
Turbo Furnace								
Big Bend No. 2	LEA, BOOS air vane adjustment	Unaffected	--	Up to 40% derate with with BOOS	--	--	--	

[a] Denotes not investigated

regarding low NO_x operation on coal-fired boilers have been the effects on boiler performance, load capacity, furnace wall tube corrosion and slagging, carbon loss, particulate loading and size distribution, other pollutant emissions, heat absorption profile, and convective section tube and steam temperatures.

Low excess air firing has become common operating practice in many utility plants as it improves boiler efficiency. Reducing stoichiometry at burners reduces both thermal as well as fuel NO_x. However, it is usually difficult to reduce excess air levels to values much below 10 or 15 percent in coal-fired boilers without excessive carbon monoxide or smoke generation. To reduce NO_x emissions to meet statutory requirements, it is often necessary to reduce burner stoichiometry down to 100 percent or lower. This can be accomplished by OSC using overfire air (OFA), burners out of service (BOOS), or biased burner firing (BBF). Minimum excess air requirements under OSC are usually higher than with LEA. In most cases, however, the excess air requirements under baseline conditions are comparable to those with OSC. The efficiency of the boiler, therefore, remains unaffected if unburned carbon loss does not increase appreciably. In some cases when, due to nonuniform fuel/air distribution or other causes, the excess air requirement increases substantially with OSC, a significant decrease in efficiency may occur. From Table 6-23, it is seen that efficiency decreases of up to 1 percent may occur under OSC. It is also seen that the same boiler (Widows Creek No. 5) tested at a different time under LEA and BOOS showed an average increase in efficiency by 1 percent. It should be emphasized that optimal boiler conditions are very important both in NO_x reduction and in minimizing potential adverse effects. Uniform fuel and air distribution to the burners is especially important for OSC operation if operation at reasonably low excess air levels is to be achieved.

Many new boilers now come factory-equipped with OFA ports. Older boilers can be retrofitted with OFA ports or can operate with minimal hardware changes under BOOS or biased firing. Burners out of service usually involves firing the higher level burners on air only while biased firing involves firing upper level burners fuel lean and lower level burners fuel rich. The optimal BOOS or biased firing pattern for low NO_x must normally be determined by trial and error although removing upper level burners from service is generally most effective. The BOOS technique is normally implemented by shutting off one or more pulverizers supplying these upper levels. If the other pulverizers cannot handle the extra fuel to maintain the total fuel flow constant, boiler derating will be required. From Table 6-23, it is seen that boiler derating of 10 to 25 percent is not uncommon with BOOS firing. Biased firing may reduce or eliminate the amount of derating a boiler has to suffer. However, this type of firing has not been tested sufficiently to establish its effectiveness as a NO_x control technique.

The possibility of increased corrosion has been a major cause for concern with OSC operation. Furnaces fired with certain Eastern U.S. bituminous coals with high sulfur contents may be especially susceptible to corrosion attack under reducing atmospheres. Local reducing atmosphere pockets may exist under OSC operation even when burner stoichiometry is slightly over 100 percent. The problem may be further aggravated by slagging as slag generally fuses at lower temperatures under reducing conditions. The sulfur in the molten slag may then readily attack tube walls. Severe slagging has been observed in some boilers operating at burner stoichiometries below 95 percent. A number of short-term corrosion tests have been carried out by inserting air cooled corrosion coupons at various locations adjacent to the water walls. The results of the tests are not quite conclusive as the rates measured by the coupons, even under baseline conditions, do not correspond to normal corrosion rates. The coupons can, however, be used to determine relative corrosion under baseline and low NO_x conditions. In general, it has been found that no significant acceleration in corrosion rates occurs under OSC conditions. Nevertheless, because of the wide scatter in data, the issue cannot be considered resolved until definitive results from long-term tests with measurements on actual water wall tubes are available.

Increased carbon loss in flyash may occur with OSC if complete burnout of the carbon particles does not occur in the furnace. High carbon loss will result in decreased boiler efficiency and may also cause electrostatic precipitator (ESP) operating problems. From Table 6-23, it is seen that increases in carbon loss vary over a wide range and can be as high as 70 to 130 percent in some cases. However, increased carbon loss is not perceived as one of the major problems associated with OSC operation. If the carbon content in flyash increases to levels where it threatens to impair the operation of dust collection systems, the unburned carbon can usually be easily controlled by increasing the overall excess air level in the furnace. Although this will tend to increase stack heat losses, the decrease in boiler efficiency will be partially compensated for by reduced unburned carbon losses.

Increased particulate loading with OSC may be a source of problems if baseline loadings are close to acceptable limits. Installing larger or more efficient dust removal devices may be necessary. The problem can be particularly severe if the particle size distribution shifts towards smaller sizes because the efficiency of many dust collectors, such as ESPs, decreases in the 0.1 to 1.0 μm range. From Table 6-23 it is seen that dust loading changes can vary widely. In some cases, dust loading may double with OSC operation, although from the few size distribution data available no shift in distribution is evident. It is suspected that increased dust loading may occur due to completion of combustion at a higher elevation in the furnace. More particles thus tend to be entrained in the stream instead of settling to the furnace hopper bottom. It should be noted, however, that most of the particulate loading measurements were carried out at the economizer outlet and do not necessarily reflect stack outlet conditions.

Extension of the combustion region to higher elevations in the furnace may result in potential problems with excessive steam and tube temperatures. However, among the numerous short-term OSC tests conducted no such problems have been reported. In some tests where furnace and convective section tube temperatures were measured directly, no significant increase was found. Changes in heat absorption profiles were also found to be minor, thus indicating no need for addition or removal of heat transfer surfaces. Superheater attemperator spray flowrates tripled in one case due to OSC operation, but in all cases were well within spray flow capacities of the units. Reheater attemperator spray flowrates did not show any increase due to OSC operation so that cycle efficiencies were not affected.

The effect of OSC operation on gaseous pollutants other than NO_x has undergone limited investigation. In one study where polycyclic organic matter (POM) was measured, an increase of about 30 percent was reported with OSC. The accuracy of POM measurement is, however, currently of the same order as the measured increase so that no conclusions can be drawn at present. Carbon monoxide (CO) emissions usually increase rapidly once burner stoichiometry or excess air levels are reduced below a certain level. This minimum level usually differs from boiler to boiler and also varies with load. Boiler operators usually establish recommended excess air levels as a function of load for each boiler. The recommended values are usually slightly higher than the minimum values to give the operator a margin of safety especially under rapidly changing load situations. When a boiler is operated under OSC, the recommended excess air levels must be reestablished as a function of load due to the higher overall excess air requirements. With proper care carbon monoxide generation should not increase significantly over baseline values. Unburned hydrocarbons (UHC) also should not exhibit any significant increase as CO is usually more sensitive to excess air levels than UHC. Total SO_x emissions should not be significantly affected by OSC operation. SO_3 conversion may actually be inhibited under air lean conditions.

Many new wall fired coal boilers are being fitted with low NO_x burners (LNB). These burners are designed to reduce NO_x levels to meet statutory requirements either alone or in some cases in combination with OFA ports. The LNB technique has the advantage of eliminating or decreasing the need for reducing or near reducing conditions near furnace walls. Corrosion problems associated with reducing atmospheres should thus not arise with this system. Although the LNB flames can be expected to be less turbulent and hence longer than flames from normal burners, the combustion zone will probably be extended less further up the furnace than the OSC. Potential changes in heat absorption profile and excessive steam and tube temperatures are, therefore, less likely to occur.

As fuel and airflows are controlled more closely in LNB-equipped systems, nonuniform distribution of fuel/air ratios leading to excessive CO generation or high excess air requirements should be eliminated. Boiler efficiencies should, therefore, not be affected by installation of LNB. However, Table 6-23 shows that the efficiency of one boiler decreased slightly when retrofitted with LNB. The decrease in efficiency was mainly due to the large increase in unburned carbon loss. Particulate loading also increased slightly with LNB, and there was a distinct shift towards smaller size particles. Still, more testing is required to check whether these changes were isolated instances or whether they form a pattern with LNB operation. It should be noted that the decrease in efficiency and increases in carbon loss and particulate loading were not greater than those encountered with OSC operation. Corrosion rates are inferred from tests with corrosion coupons showed no significant increase with LNB. Some BOOS tests were also carried out on the LNB-equipped boiler. A substantial decrease in NO_x emissions resulted below those already achieved with LNB alone. However, the boiler was derated by up to 30 percent. Other potential problems associated with OSC could also arise with this type of firing.

Flue gas recirculation to the windbox has been tested as a NO_x control technique for coal-fired boilers (Reference 6-5). The technique inhibits thermal NO_x formation but is not very effective in controlling fuel NO_x. The technique has not been used widely on coal-fired units. The tests on Hatfield No. 3 showed that OSC was indeed much more effective in controlling NO_x than FGR. Table 6-23 summarizes some of the effects of FGR operation on that unit. The increase in carbon loss averaged 120 percent, although there were wide variations in the measured values. Load capacity and dust loading remained unaffected. There was a slight decrease in boiler efficiency attributable to the power consumption by the FGR fans. There was no significant increase in tube temperature and POM emissions remained essentially unchanged. Stable flames and uniform combustion were observed throughout the tests even at high recirculation rates (up to 15 percent at full load and 34 percent at reduced loads). Reheat steam spray attemperation increased at high recirculation rates which would result in a loss in cycle efficiency. Higher convective section heat transfer rates may be expected with FGR as the higher gas mass flowrates over the tubes tend to increase the convective coefficients. No corrosion measurements were made so that the effect of FGR on corrosion is not known. Corrosion due to chemical attack is not expected to be a major problem with FGR. However, tube erosion may increase as the higher gas velocities may result in greater particle impact on exposed surfaces.

Some data were available on the effect of water injection on NO_x emissions. Water injection, however, results in a significant deterioration of boiler performance. It has therefore not been recommended as a long-term NO_x control measure for coal-fired boilers.

It should be emphasized that the effects of NO_x control, in many cases, will be critically dependent on boiler operating conditions. Factors such as boiler cleanliness and uniform air and fuel distribution can have a significant effect on the impacts of NO_x controls on both emissions and boiler operations. It is therefore important that adequate maintenance procedures are instituted. In some cases, normal maintenance and overhaul schedules may have to be modified. In addition, when potential problems such as tube corrosion and high tube temperatures are expected, the boiler operator will have to pay closer attention to tube conditions and watch for evidence of incipient failure. In a few cases hardware modifications may be indicated, e.g., removal of reheater or superheater surface if attemperation requirements become excessive. Furthermore, if attemperation leads to a significant decrease in cycle efficiency, removal of reheater surface may be indicated. Still, with proper design of retrofit systems and adequate maintenance programs, low NO_x operation should not result in a substantial increase in operational problems over normal boiler operation.

6.14.2 Oil-Fired Boilers

The effects of low NO_x operation on oil-fired boilers are summarized in Table 6-24. The most common low NO_x techniques tested for oil-fired boilers are low excess air (LEA), off stoichiometric combustion (OSC), and flue gas recirculation (FGR). Other techniques which have been tested but are less commonly employed are water injection (WI) and reduced air preheat (RAP). The major concerns regarding low NO_x operation on oil-fired boilers are effects on boiler performance, load capacity, vibration, and steam and tube temperatures.

Low excess air is currently employed in many utility boilers due to the beneficial effect it has on efficiency. Improvements in boiler efficiency up to 5 percent have been reported in addition to lower fan power consumption due to the smaller volume of air and gas flows. Still, LEA may, in some cases, result in lower steam temperature which will adversely affect cycle efficiency. To obtain the minimum possible excess air levels, it is necessary to ensure uniform air and fuel flows. This often requires adjusting air dampers and vanes and may also necessitate cleaning or replacing burner tips. It is usually, however, very difficult to reduce excess air levels much below 10 percent without raising carbon monoxide or smoke emissions. Low excess air is, therefore, usually effective as a NO_x

TABLE 6-24. EFFECT OF LOW NO_x OPERATION ON OIL-FIRED BOILERS

Boiler	Low NO_x Technique	Efficiency	Load Capacity	Vibration and Flame Instability	Steam and Tube Temperatures	Other Effects, Comments
Tangential						
South Bay No. 4	LEA	5% increase	--[a]	--[a]	--[a]	No adverse effects reported. Fan power consumption reduced.
	BOOS	Decrease in efficiency compared to LEA due to increased excess air requirements				No other adverse effects reported
	RAP	Unaffected due to special preheater design	--	--	--	Limited tests. NO_x control effectiveness not demonstrated.
Pittsburg No. 7	OFA and FGR	--[a]	Slower startups and load changes	FGR fan vibration problems	High water wall tube temperatures	
SCE tangential boilers	BOOS and FGR	--	--	--	--	No adverse effects reported
Opposed Wall						
Moss Landing Nos. 6 and 7	OFA and FGR	Increased excess air requirements resulting in decreased efficiency	--	FGR fan and duct vibration, furnace vibration problems. Associated flame instability.	--	High furnace pressures. Increased FGR and forced draft fan power assumption.
Ormond Beach Nos. 1 and 2	BOOS and FGR	Increased excess air requirements resulting in decreased efficiency	10 to 15% derate due to maxed FD fan capacity	Flame instability and associated furnace vibration	--	Flame detection problems due to change in flame characteristics
	Water injection	Increased sensible and latent stack losses	--	--	--	Limited tests carried out with WI at partial loads. Excess air requirements increased.
SCE B&W Units	BOOS and FGR	FGR reduced minimum excess air requirements increasing unit efficiency	--	Boiler vibration problems	--	Flame detection problems due to change in flame characteristics
Sewaren Station No. 5	LEA, BOOS	--	--	--	--	Tests carried out at partial loads. No adverse effects reported. Particulate loading and size distribution unaffected.
FW Unit C	BOOS and FGR	--	15% derate to vibration and limited FD fan capacity	Flame instability and associated furnace vibration	--	OFA ports very effective in controlling NO_x

[a] Denotes not investigated

TABLE 6-24. Concluded

Boiler	Low NO_x Technique	Efficiency	Load Capacity	Vibration and Flame Instability	Steam and Tube Temperatures	Other Effects, Comments
Single Wall						
Encina Nos. 1, 2 and 3	LEA and BOOS (2 burners on air only)	Increased unit efficiency. Some adverse effect on cycle efficiency due to lower steam temperatures.	--[a]	--[a]	Decrease in SH & RH steam temperature	No other adverse effects reported
	BOOS (3 burners on air only)	Increased excess air requirements resulting in reduced efficiency	5% derate due to maxed ID fan capacity	In most tests no flame instability or blowoff noted	Intermittent flame carryover to SH inlet but tube temperature limits not exceeded	No abnormal tube fouling, corrosion or erosion noted. Increased tendency to smoke and obscure flame zone.
Turbo						
South Bay No. 3	Airflow adjustments	Slight reduction in EA resulting in slight increase in efficiency	--	--	--[a]	No adverse effects reported
	Water injection	6% decrease at full load	--	No flame instability noted even at high rates of WI	--	No other adverse effects reported
	Reduced air preheat	Reduction in efficiency greater than that with water injection	--	--	--	Limited tests
Potrero No. 3-1	OFA and FGR	Higher excess air requirements, but addition of economizer surface expected to improve efficiency	5% derate due to excessive tube temperatures	Side to side windbox oxygen cycling	Tube and steam temperature limits approached. Increased SH tube failures.	Increased tendency to smoke required higher minimum excess O_2 levels. RH surface removed to avoid excessive RH steam attemperation. Larger economizer installed to compensate for RH surface removal.

[a] Denotes not investigated

control technique when the baseline emissions are only slightly higher than the statutory limits.

Off stoichiometric combustion has been found to be an effective technique for NO_x control from oil-fired boilers. The technique inhibits both thermal and fuel NO_x formation. Many new boilers come equipped with OFA ports as standard equipment. Older boilers may be retrofitted with OFA ports or operated with BOOS or biased firing. As with LEA it is important that a uniform air and fuel distribution be maintained at all burners in order to minimize CO and smoke emissions. Boiler operation with OSC generally increases the minimum excess air requirements which may result in a loss in boiler efficiency. In extreme cases when the boiler is operating close to the limits of its fan capacity, boiler derating may be required. Derates of as much as 15 percent have been reported due to the lack of capability to meet the increased airflow requirements at full load.

In many cases, BOOS operation in oil-fired boilers has been found to be more effective in controlling NO_x than OFA firing. The BOOS technique involves firing a few burners, usually from the top rows, on air only, although the optimal BOOS pattern which will result in maximum NO_x reduction must usually be determined by trial and error. The fuel flow to the rest of the burners thus increases if load is to remain constant. In some cases, it has been necessary to enlarge the burner tips in order to accommodate these increased flows.

No flame instabilities or boiler vibrations have been noted with BOOS firing, nor are they expected with any type of OSC operation alone. However, OSC operation results in an extended combustion zone. In some cases flame carryover to the convective section may occur. However, in one case where intermittent flame carryover occurred, no excessive tube temperatures were recorded. Also no abnormal tube fouling or corrosion was encountered. In another test, particulate loading and size distributions were measured under OSC operation. No significant differences were found from baseline values. OSC operation does usually result in hazy flames and obscure flame zones. Thus, new flame scanners and detectors are often required due to the change in flame characteristics. Except for the above, no other major adverse effects have been reported in the numerous short and medium tests conducted with OSC on oil-fired boilers.

Flue gas recirculation can also be employed to reduce mainly thermal NO_x emissions from oil-fired boilers. Implementing FGR for NO_x control usually requires retrofit hardware modification to boilers as FGR is more effective when it is recirculated to the windbox than to the furnace hopper. Some boilers come equipped with FGR to the hopper for steam temperature control. These then require booster fans to introduce the flue gas to the windbox. In boilers with no original FGR capability, FGR fans and ducting must be installed along with appropriate splitter vanes and mixing devices.

There are a number of potential problems which can occur with FGR retrofit operation. The most common problems, such as FGR fan and duct vibrations, can usually be avoided by good design. Other problems such as flame instability, which can lead to furnace vibrations, are caused by the increased gas velocity at the burner throats. Modifications to the burner geometry and design such as enlarging the throat, altering the burner tips, adding diffuser plates or flame retainers, and in one case, providing tertiary airflow around the oil gun may then be required. These modifications are usually made by trial and error for each boiler and are often very time consuming. If the problem of excessive boiler vibration and flame instabilities persists at high loads, the boiler may have to be derated.

Other problems associated with FGR are high tube and steam temperatures in the convective section. The increased mass velocities which occur with FGR cause the convective heat transfer coefficient to rise. This may, in extreme cases, lead to tube failures, exceeding attemperator spray flow limits, or loss in cycle efficiency due to excessive reheat steam attemperation. Increased mass flowrates in the furnace may also cause furnace pressures to increase beyond safe limits. Flue gas recirculation usually, however, has an advantage of not increasing minimum excess air levels. Boiler efficiency is therefore relatively unaffected except for the power consumed by the FGR or booster fans.

There is a paucity of data on boilers operated with FGR alone. Boilers are usually tested with OSC first to check whether the NO_x reductions are sufficient to meet regulations. If not, FGR capability is added. The combination of OSC and FGR is very effective in reducing NO_x emissions. However, the problems associated with each technique are also combined. Tube and steam temperature problems in the upper furnace are particularly aggravated, as both OSC and FGR tend to increase upper furnace temperatures and heat transfer rates. Otherwise the comments for OSC and FGR alone also apply to their combined operation. Boiler efficiencies usually decline slightly with combined OSC and FGR firing due to higher EA requirements and greater fan power consumption.

Water injection has been tested in a few instances as a NO_x control technique. It is generally relatively simple to implement. Water is sprayed directly into the combustion air by a bank of nozzles installed in the air duct downstream of the preheater. In one series of tests it was found to be as effective as FGR. However, WI carries a heavy penalty in reduced efficiency due to stack latent heat losses. Excess air requirements often increase, contributing to a decrease in efficiency. In one case an increase in fuel flow of 6 percent was required to maintain full load. However, no flame instabilities or other adverse effects were noted. For the above reasons, though, WI is generally used as an interim NO_x control measure until a permanent, less energy wasteful technique can be initiated.

Reduced air preheat has also been tested as a NO_x control measure. On oil fuels the test results on its effectiveness are mixed. RAP usually leads to severe losses in efficiency due to increased stack gas temperatures. On one boiler, it was estimated that for the same reduction in NO_x, WI resulted in lower efficiency losses than RAP. However, in special cases where the air heater and boiler are of unique design, a boiler designed to incorporate a steam coil preheater instead of an air/gas heat exchanger, RAP may be employed without any theoretical decrease in boiler efficiency. As tests conducted with RAP have been limited in nature, no data are available on the effect of RAP on other aspects of boiler operation.

Operating with low NO_x burners would seem to be a promising NO_x control technique for wall fired boilers. Many of the deficiencies associated with other techniques would be eliminated. Several manufacturers in the U.S. are in the process of developing and testing LNB for oil-fired boilers. However, no test data have been released to evaluate the effectiveness of the burners. Nevertheless, once LNB for oil-fired burners are commercialized, they will probably become one of the more important NO_x control measures employed for wall fired boilers.

In certain boilers, such as turbo furnaces, burner air dampers and vanes can be adjusted to create airflow patterns in the furnace resembling an overfire air effect. By balancing airflows, it may also be possible to reduce excess air requirements at the same time. As the reduction in NO_x levels is generally small, this technique, like LEA, is useful when baseline NO_x emissions are close to regulatory limits.

As with coal-fired boilers, before low NO_x techniques are instituted on an oil-fired boiler, it is important to assure that it is in good operating condition. Uniform burner air and fuel flows are essential for optimal NO_x control. Retrofit NO_x control systems must be designed and installed properly to minimize potential adverse effects. Despite these precautions, in some cases inevitable problems will occur, such as flame instability or high tube temperatures. In some of these cases problem shooting by trial and error and certain hardware modification will be required to resolve the problems. In other cases, increased vigilance will be needed on the part of the boiler operator, and an accelerated schedule of maintenance and overhaul may be required. Changes to the boiler safety and control systems may also be required, such as installation of new flame scanners and modification of combustion control for new minimum excess air levels. In some cases the boiler will be unable to function on automatic control requiring manual operation. Some boilers may have their startup procedures and load pickup responses altered due to FGR fan preheating requirements, etc. Very many of the problems can now be avoided because of hindsight and experience. Thus, retrofit systems can now be designed and installed with care to avoid any potential adverse effects. New units with built-in OFA and FGR systems or LNB should function without problems.

6.14.3 Gas-Fired Boilers

The effects of low NO_x operation on gas-fired boilers are summarized in Table 6-25. The low NO_x techniques used and their effects are very similar to those for oil-fired boilers. Usually there is no distinction between oil- and gas-fired boilers as they are often designed to switch from one fuel to the other according to availability. Since the NO_x control method, the effects of low NO_x operation, and the boilers themselves are similar for gas and oil, a detailed discussion of gas-fired boilers will not be given here. Most of the above discussion of applicable NO_x control measures to oil-fired boilers and potential problems resulting

TABLE 6-25. EFFECT OF LOW NO$_x$ OPERATION ON GAS-FIRED BOILERS

Boiler	Low NO$_x$ Technique	Efficiency	Load Capacity	Vibration and Flame Instability	Steam and Tube Temperatures	Other Effects, Comments
Tangential						
South Bay No. 4	LEA	2 to 3% increase	--[a]	--[a]	--[a]	No adverse effects reported
	BOOS	Decrease in efficiency compared to LEA due to increased excess air requirements				No other adverse effects reported
Pittsburg No. 7	OFA and FGR	--[a]	**25% derate due to excessive steam temperatures. Slower load change response**	Fan and duct vibration problems	High tube and RH steam temperatures	
Horizontally Opposed						
Moss Landing Nos. 6 and 7	OFA and FGR	0.8% decrease in cycle efficiency due to RH steam attemperation	Load curtailment to 50% after oil burns due to SH tube temperature limits being exceeded	Furnace and duct vibration problems. Flame instability.	RH spray and SH tube temperature limits approached after oil burns upper wall tube failures	Furnace pressure limit approached. FGR fan power requirements increased by as much as 66%. Problems associated with switching to gas after oil burning could be eliminated only with complete water washing of furnace.
Pittsburg Nos 5 and 6	OFA and FGR	--	--	FGR fan and duct vibrations. Flame instability problems.	Upper water wall tube failures	Boiler initially restricted to manual operation due to problems with flame instability on automatic control
Contra Costa Nos. 9 and 10	OFA and FGR	--	--	FGR duct vibrations	High SH and RH steam temperatures. SH tube temperature limits being approached.	Furnace pressure limits approached after oil firing. FGR fan preheating required to reduce vibrations on cold boiler startups.
Single Wall						
Encina Nos. 1, 2 and 3	BOOS (2 and 3 burners out of service)	Low EA levels were possible even with BOOS, resulting in increased efficiency	No derate. Load pickup response not affected	Some pressure pulsing at corners of firebox	Some flame carryover to SH but no problems with high tube temperature or tube wastage	No other adverse effects reported

[a] Denotes not investigated

TABLE 6-25. Concluded

Boiler	Low NO_x Technique	Efficiency	Load Capacity	Vibration and Flame Instability	Steam and Tube Temperatures	Other Effects, Comments
Turbo						
South Bay No. 3	Air flow adjustments	Slight reduction in EA resulting in slight improvement in efficiency	--[a]	--[a]	--[a]	No adverse effects reported
	Water injection	10% decrease at full load	--	No flame instability noted even at high rates of WI	--	No other adverse effects reported
Potrero No. 3-1	OFA and FGR	Installation of larger economizer expected to improve efficiency	5% derate due to problems with high temperatures	Side to side windbox oxygen cycling	Tube metal and steam temperature limits reached at high loads	Hardware modifications included partial RH surface removal to avoid excessive RH steam attemperation. Larger economizer then installed to compensate for smaller RH surface.

[a] Denotes not investigated

applies. Some effects specific to gas-fired boilers alone are treated briefly below.

NO_x emissions oftentimes are difficult to control after switching from oil to gas firing. Residual oil firing tends to foul the furnace due to the oil ash content. Thus, NO_x control measures which have been tested on a clean furnace with gas may be found inadequate after oil firing due to the changed furnace conditions. These problems can be resolved by complete water washing of the furnace after any oil burns. This is not very practical, however, especially if oil to gas fuel switching occurs frequently.

Boilers fired with gas usually have higher gas temperatures at the furnace outlet than when fired with oil. Gas flames are not very luminous and therefore radiate less energy to the furnace walls than oil flames. The upper furnace and convective section inlet surfaces are thus subject to higher temperatures with gas firing. These temperatures may increase further when the combustion zone is extended due to OSC. Furthermore, heat transfer rates in the convective section will rise with increased mass velocities due to FGR. Upper furnace and convective section tube failures and excessive steam temperatures are therefore more likely to occur when OSC and FGR are implemented on gas-fired boilers. The situation may be aggravated further if switching from gas fuel occurs after oil burns as fouling will further reduce furnace absorption and, hence, increase gas temperatures. Excessive steam temperatures or attemperation can be corrected by partial removal of superheater or reheater surface. Excessive tube temperatures will usually result in a derating of the system.

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SECTION 7

COST OF COMBUSTION MODIFICATION CONTROLS

It is generally agreed by boiler manufacturers and utility companies alike, that the reliable estimation or projection of NO_x control costs for utility boilers is a difficult task indeed. Control equipment needs and control costs are highly dependent on an individual boiler's characteristics, as well as on individual installation and operational problems (References 7-1 through 7-6). Therefore, in this study, control costs for typical boilers were analyzed. They should be taken as such -- typical costs and not necessarily the norm for all cases.

In Section 7.1, previously reported cost estimates are reviewed and cost analysis needs identified. Based on the need for a standardized cost analysis procedure for comparing the cost effectiveness of controls, Section 7.2 develops the cost calculation procedure used in this study. Section 7.3 analyzes in detail typical retrofit control costs, based on preliminary design studies, equipment vendor quotes, and engineering estimates. The incremental costs of implementing controls to new boilers meeting current NSPS are presented in Section 7.4, based on the latest design estimates from a major boiler manufacturer.

In all the control cases considered, the projected control costs are documented as thoroughly as available data allow. However, it should be reiterated that the presented numbers should only be considered as representative of typical cases -- there is no such thing as a standard boiler or control application. Furthermore, there are still unanswered questions from long term operation with controls, such as possible increased corrosion, slagging, and associated maintenance costs.

7.1 BACKGROUND

One of the earliest efforts at assigning costs to combustion modification control techniques for utility boilers was attempted by Esso Research and Engineering in 1969 (Reference 7-7). Since 1969, however, it has been shown that the effectiveness of control techniques among boilers varies widely and requires continuing cost effectiveness evaluations on an individual boiler basis. As an example of cost variations for combustion modifications among individual existing units, several case studies from Pacific Gas and Electric are presented in Table 7-1 (Reference 7-8). The numbers shown are the costs incurred by PG&E during a recent program to bring eight oil-fired units into compliance with local NO_x emission regulations. For the most part, the conversions involved the combination of windbox flue gas recirculation and overfire air ports. Although the average cost of the modifications was about $10/kW, in 1975 dollars, they ranged from $1.8/kW to $17/kW.

Another West Coast electric utility company, the Los Angeles Department of Water and Power (LADWP), has had extensive experience in implementing NO_x control techniques on its gas- and oil-fired boilers. The techniques currently utilized by the Department include burners out of service, overfire air, and low excess air. Table 7-2 shows the NO_x control installation costs incurred by LADWP for four different units (Reference 7-9). The figures for the BOOS technique reflect the R&D costs that preceded the retrofit. The very low expense associated with OFA on on the B&W 235 MW unit was due to the base year of that estimate (1964 to 1965), and to the fact that this modification was included in the original design. For the most part, the LADWP boilers were modified without much difficulty, and the associated costs probably represent the lower limits of the costs for the three NO_x reduction techniques implemented.

The modification costs presented by PG&E and LADWP were only gross estimates. Many different organizations were involved in the retrofit efforts cited, and as a consequence, cost sharing and accounting often obscured the true costs. Furthermore, research and development costs, which could only be crudely estimated, significantly raised or lowered cost figures, depending on whether or not they were included. Finally, the rush to meet new local air pollution regulations often increased control implementation costs greatly (References 7-4 and 7-5).

TABLE 7-1. 1975 INSTALLED EQUIPMENT COSTS FOR EXISTING PG&E RESIDUAL OIL-FIRED UTILITY BOILERS (Reference 7-8)

Unit Name	Design Type	Year Online	Capacity (MW)	Modification Cost ($$10^6$)	$/kW	Year Modified	Type of Modification
Pittsburg No. 7	CE tangential fired, divided	1972	730	6.2 $(6.9)^a$	8.5 $(9.4)^a$	1975	Windbox FGR, Overfire Air • Two new 5000 hp FGR fans • FGR ducting (17% FGR) • NO_x port installation • No new burner safeguard system
Pittsburg Nos. 5 and 6	B&W opposed wall	1964	330 (each)	7.8 (both) $(8.7)^a$	11.8 $(13.1)^a$	1975	Windbox FGR, Overfire Air • Transferred two FGR fans from other units • FGR ducting (17% FGR) • New hopper • NO_x port installation; one for each burner column • New burner safeguard system; computer, NO_x control board, O_2 controls on dampers, flame scanners
Nos. 9 and 10 Contra Costa	B&W opposed wall	1965	345 (each)	6 (both) $(6.7)^a$	8.7 $(9.7)^a$	1975	Windbox FGR, Overfire Air • New FGR fans (1 each) (17% FGR) • Nominal amount of new ducting to windbox • NO_x port installation
Potrero No. 3	Riley turbo furnace	1972	206	3.5 $(3.9)^a$	17 $(18.9)^a$	1975	Windbox FGR, Overfire Air • New FGR fan (17% FGR) • NO_x port installation, nominal amount of ducting • New burner safeguard system, NO_x control board, computer
Moss Landing Nos. 6-1 and 7-1	B&W opposed wall	1967, 1968	750 (each)	2.8 $(3.1)^a$	1.8 $(2.0)^a$	1971	Windbox FGR, Overfire Air • Existing temperature control FGR fans replaced with larger fans • New flame scanners

[a] 1977 dollars in parenthesis

TABLE 7-2. LADWP ESTIMATED INSTALLED 1974 CAPITAL COSTS FOR NO_x REDUCTION TECHNIQUES ON GAS- AND OIL-FIRED UTILITY BOILERS (Reference 7-9)

Unit Capacity (MW)	Unit Type	NO_x Reduction Technique	Implementation Method	Estimated Cost, \$ 10^3		\$/kW	
180	CE Single Wall	BOOS	Retrofit	69.4	(84.2)[b]	0.38	(0.46)[b]
235	CE Single Wall	BOOS	Retrofit	28.9	(35.1)	0.16	(0.19)
235	B&W Opposed Wall	BOOS	Retrofit	75.2	(91.3)	0.32	(0.39)
		Overfire air	Original Design	14.0[a]	(17.0)	0.06	(0.07)
		LEA	Retrofit	28.9	(35.1)	0.12	(0.15)
350	B&W Opposed Wall	BOOS	Retrofit	266.0	(323.0)	0.76	(0.92)
		Overfire Air	Retrofit	101.0	(122.0)	0.29	(0.35)
		LEA	Retrofit	28.9	(35.1)	0.08	(0.10)

[a] 1964-65 base year

[b] 1977 dollars in parenthesis

In another study, Lachapelle (Reference 7-10) estimated costs for operating under low excess air conditions. Generally, no significant additional cost for modern units or units in good condition is required for reducing excess air. However, some older units may require modifications such as altering the windbox by adding division plates, separate dampers and operators, fuel valving, air register operators, instrumentation for fuel and airflow, and automatic combustion controls. Table 7-3 shows estimated investment costs for LEA firing on existing utility boilers (Reference 7-10). These costs are guidelines which can vary depending on the modifications that are required. As unit size increases, the cost per kW decreases since the larger units typically have inherently greater flexibility and may require less extensive modification.

TABLE 7-3. 1974 ESTIMATED INVESTMENT COSTS FOR LOW EXCESS AIR FIRING ON EXISTING BOILERS NEEDING MODIFICATIONS (Reference 7-10)

Unit Size (Electrical Output) (MW)	Investment Cost, $/kW	
	Gas and Oil	Coal
1000	0.12 (0.15)[a]	0.48 (0.58)[a]
750	0.16 (0.19)	0.51 (0.62)
500	0.21 (0.25)	0.55 (0.67)
250	0.33 (0.40)	0.64 (0.78)
120	0.53 (0.64)	0.73 (0.89)

[a] 1977 dollars in parenthesis

The use of low excess air firing reportedly increases boiler efficiency by 0.5 to 5 percent. Additional savings may result from decreased maintenance and operating costs, so any investment costs can be offset by savings in fuel and operating expenses.

The best documented control costs to date have been those of Selker and Blakeslee (References 7-11 and 7-12). Costs for the combined use of overfire air ports and low excess air firing for both new and existing units are summarized from these studies in Figures 7-1 and 7-2. Capital costs were projected over a unit size range of 25 to 1000 MW. Figure 7-1 applies to new unit designs with heating surfaces adjusted to compensate for the resultant changes in heat transfer and rates. Figure 7-2 applies to existing units with no change in heating surface, as these changes must be calculated on an individual unit basis. Cost ranges for existing units vary more widely than for new units, since variations in unit design and construction can either hinder or aid the installation of a given NO_x control system. It can be noted from Figures 7-1 and 7-2 that the average (not the range of) modification cost on a per kilowatt basis is not a strong function of equipment size. In other words, for the purposes of cost estimation, there are no significant economies of scale since the "error band" in the original estimate is so broad. This fact will be put to use in the cost estimations of Section 7.3.

In addition to the increased capital costs for including OFA in new or existing units, Selker and Blakeslee reported differential operating costs for 500 MW new and existing boilers, as shown in Table 7-4 (Reference 7-12). To put these operating costs in perspective, they can be compared to the percent increase in generating costs shown at the bottom of Table 7-4. Except for the case of older units, the difference in operating cost is below 0.1 percent of annual cost.

The results of Selker and Blakeslee, though valuable, are for a particular control case only, overfire air for tangential coal-fired boilers. The most recent cost estimates are those of Krippene for oil- and gas-fired boilers (Reference 7-13). Table 7-5 gives the estimates for investment costs and total annual cost. Unfortunately, the initial investment cost of controls, including hardware requirements and costs, were not documented.

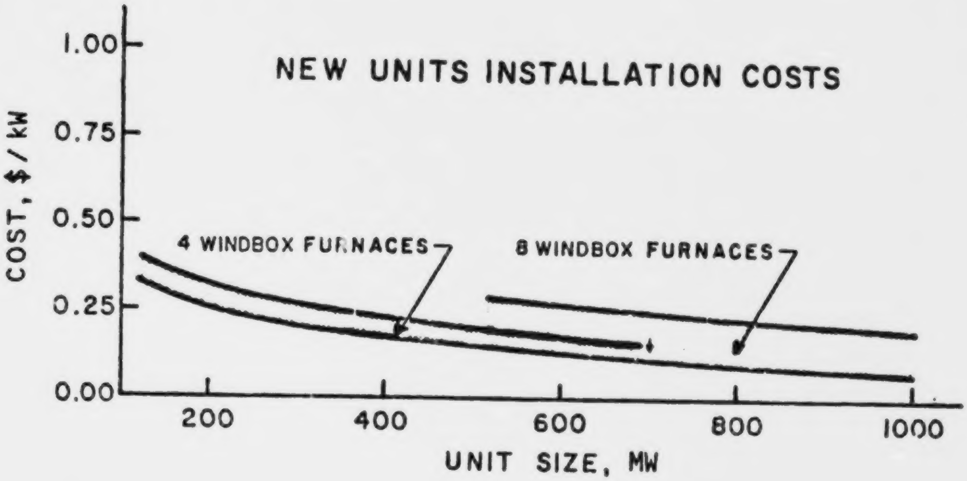


Figure 7-1. 1975 capital cost of OFA on new tangential coal-fired boilers (Reference 7-11).

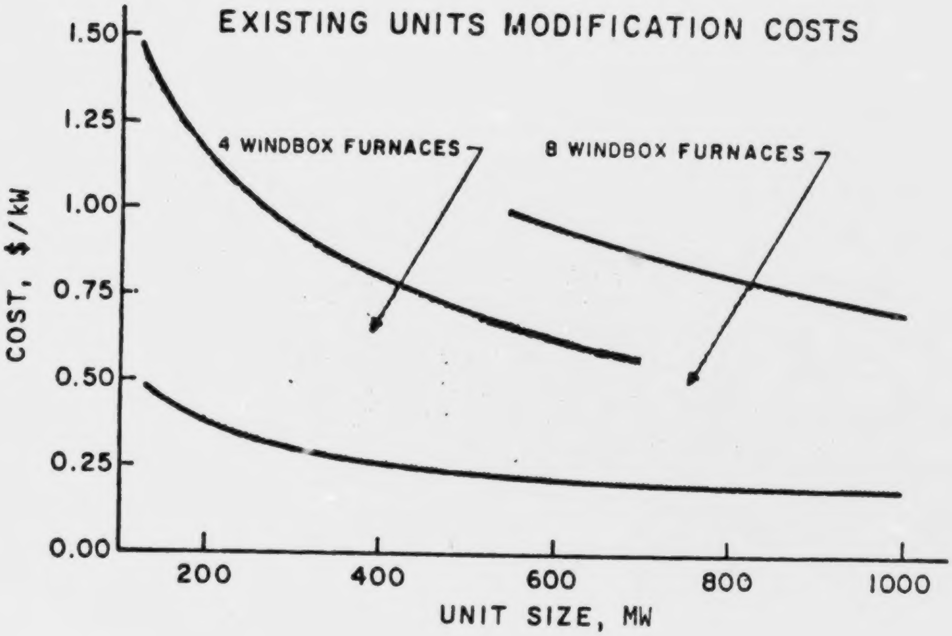


Figure 7-2. 1975 capital cost of OFA on existing coal-fired boilers (Reference 7-11).

TABLE 7-4. 1975 DIFFERENTIAL OPERATING COSTS OF OFA ON NEW AND EXISTING TANGENTIAL COAL-FIRED UTILITY BOILERS (Reference 7-12) (Net Heat Rate 10 MJ/kWh, March 1975 Equipment Costs)*

	New Plant Without Overfire Air	New Plant With Overfire Air	Recent Existing With Added Overfire Air	Older Existing Without Overfire Air	Older Existing With Added Overfire Air
Capital Cost ($/kW)	500.00	500.20	500.70	250.00	250.70
Annual Capital Cost ($)	40,000,000[a]	40,016,000	40,056,000	20,000,000[b]	20,056,000
Annual Fuel Cost ($)	18,000,000[c]	18,000,000	18,000,000[d]	9,000,000	9,000,000
Labor and Maintenance ($)[e]	8,100,000	8,100,000	8,100,000	8,100,000	8,100,000
Total Annual Cost[f] ($)	66,100,000	66,116,000	66,156,000	37,100,000	37,156,000
Electricity Cost (mills/kWh)[g]	24.481	24.487	24.502	13.741	13.762
Increase (%)	--	0.024	0.086	--	0.153
Increase (mills/kWh)[f]	--	0.006	0.021	--	0.021

[a] Annual fixed charge rate of 16 % x 500 $/kW x 500,000 kW

[b] 16 % x 250 $/kW x 500,000 kW

[c] 0.66 $/GJ coal cost x 5,400 hr/yr x 500,000 kW x 10 MJ/kWh

[d] 0.33 $/GJ coal cost x 5,400 hr/yr x 500,000 kW x 10 MJ/kWh

[e] Labor and maintenance cost of 3.0 mills/kWh

[f] 5,400 hr/yr at 500 MW -- 2,700 GWh/yr

[g] Cost at plant bus bar; transmission and distribution not included

*To convert to 1977 dollars, multiply 1975 dollars by 1.2 factor

TABLE 7-5. COSTS FOR NO_x EMISSION CONTROLS ON ELECTRIC POWERPLANTS USING GAS- AND OIL-FIRED STEAM GENERATION EQUIPMENT (1977 DOLLARS) (Reference 7-13)

	Existing Powerplants		New Powerplants	
	Staged Combustion[a]	Staged Combustion Plus FG Recirculation (Best Effort Basis)	Staged Combustion[a]	State of the Art NO Control
Investment ($/kW)	0.4 to 2.0	7.0 to 11.0	0.5 to 1.50[c]	5.0 to 12.0
Fixed Capital Charges ($/kW-yr)	0.08 to 0.4	1.4 to 2.2	0.1 to 0.3	1.0 to 2.4
Operation and Maintenance Cost ($/kW-yr)	0.02 to 0.1	0.35 to 0.55	0.025 to 0.075	0.25 to 0.6
Fuel Cost Penalty ($/kW-yr)	0.31	1.24	0.15 to 0.31	0.62 to 1.24
Annual Cost ($/kW-yr)	0.41 to 0.81	2.99 to 3.99	0.275 to 0.685	1.87 to 4.24

[a] Fixed capital charges = 20%, O&M costs = 5%, fuel penalty = (0.12 - 0.25%) x $2.85/GJ x 5000 hrs/yr

[b] Fixed capital charges = 20%, O&M costs = 5%, fuel penalty = (0.5 - 1.0%) x $2.85/GJ x 5000 hrs/yr

Net plant heat rate = 9.71 MJ/kWh

[c] To meet current EPA NO_x emission requirements: i.e., 86 ng/J, gas; 129 ng/J, oil

7.2 COST ANALYSIS PROCEDURES

Given the background of control cost estimation discussed in the previous section, there is an evident need for a systematic, well documented, up to date cost analysis of typical controls for representative boiler design/fuel classifications. In this way, the cost effectiveness of controls can be compared from boiler to boiler on an even basis.

Therefore, the use of accepted estimation procedures for costing NO_x control implementation in current dollars was employed in this study, with heavy reliance on discussions with boiler manufacturers, equipment vendors, and utilities. For the case of retrofit control costs, preliminary design work was performed to allow estimation of hardware and installation needs, as well as engineering requirements. The analysis was applied to a number of cases to give a range of retrofit control costs. For the cost of NO_x controls in new boilers, the services of two major suppliers, the Babcock & Wilcox Company and the Foster Wheeler Energy Corporation, were enlisted. Their estimates are presented in Section 7.4.

For the analysis of the cost of controls, regulated public utility economics were adopted. These are governed by the following principles (Reference 7-14).

- Permitted revenue - (current operating disbursements + depreciation + interest paid on debt) = taxable income
- Taxable income x effective tax rate = income taxes
- Permitted revenue = current operating disbursements + depreciation + income taxes + (fair return x rate base)

Permitted revenue is often called revenue requirement by utilities. Thus, the latter term is adopted in the following. Based on the revenue requirement approach, an annualized cost methodology was developed, adapted from that used by the Tennessee Valley Authority in evaluating the cost of power plant projects for EPA (Reference 7-15) and EPRI (Reference 7-16). This procedure has been generally accepted in the industry (References 7-17 through 7-19).

For the present application, the additional revenue requirement represents the incremental cost of operating a boiler under controlled conditions over and above the cost of operating the same boiler uncontrolled. In other words, the revenue requirement takes into account the initial investment, the annual capital charges resulting from that investment, and all direct operating costs such as operation and maintenance. Once the revenue requirement RR(n) for each year n that the utility operates the control up to N years (the remaining lifetime of the boiler) is obtained, an annualized cost, or a discounted level annual cost can be evaluated. Using basic economics (Reference 7-14):

$$\text{Annualized Revenue Requirement} = \frac{j(1 + j)^N}{(1 + j)^N - 1} \cdot \left[\sum_{n=1}^{N} \frac{RR(n)}{(1 + j)^n}\right]$$

The first term of the product is the capital recovery factor, which recognizes the time value of money by discounting at an annual cost of capital of j x 100 percent (effective interest rate). The effective interest rate j is given by:

$$j = bi + (1 - b)r$$

where b is the debt/equity ratio, i is the interest rate on this borrowed money (debt), and r is the rate of return to equity. According to the Edison Electric Institute (Reference 7-20), the debt/equity ratio for the utility industry has been relatively constant over recent years and $b = 0.5$ is a good estimate. The interest rates i and r were taken as 0.08 and 0.12, respectively (References 7-15 and 7-16).

With the annualized revenue requirement or annualized cost approach, the details of calculating RR(n) will be presented. The revenue requirements for each year n are given by the sum of direct operating costs and indirect operating costs.

$$RR(n) = DOC + IOC(n)$$

where DOC is given by the sum of the following incremental costs:

- Fuel penalty under controlled conditions
- Fuel credit (for unused fuel if forced to derate)
- Raw materials

- Conversion costs
  - Additional operating personnel
  - Additional utilities requirements
  - Additional maintenance
  - Required analyses
- Annual royalties (if any)
- Purchased power (if forced to derate)

and IOC(n) is given by the sum of the following incremental costs:

- Capital charges
  - Depreciation
  - Insurance
  - Replacement costs
  - Cost of capital and taxes
- Capital charges of lost capacity (if forced to derate)
- Overhead
  - Administrative overhead
  - Plant overhead

Indirect operating costs represent overhead as well as the capital charges due to the initial investment and any lost capacity. This lost capacity charge will be discussed later in this section. The initial investment is given by the sum of the following costs:

- Engineering design and supervision
- Engineering fee
- Hardware requirements
- Installation labor and supervision
- Construction facilities
- Service facilities
- Utilities facilities
- Construction field expense
- Contractor's fee
- Construction contingency
- Initial charges (such as licensing fees, if any)
- Startup costs

The appropriate equations or estimation procedures for calculating all of the above cost factors are presented in Table 7-6.

TABLE 7-6. COST ANALYSIS CALCULATION ALGORITHM[a]

Cost Factor	Calculation Equation	Reference
Initial Investment, II	$II = (DI + IND + SC + IC)$, as per below	
Engineering Design & Supervision, DS	DS estimated from preliminary design work	This report, Section 7.3
Engineering Fee, EFEE	$EFEE = 0.08 \times DS$	Engineering estimate
Hardware, TM	TM from preliminary design work	Vendor quotes
Installation Labor & Supervision, TL	TL from preliminary design work and engineering estimate	This report, Section 7.3
Construction Facilities, CF	$CF \approx 0.05 \times (TL + TM + UF + SF)$	TVA (References 7-15, 7-16)
Service Facilities, SF	$SF \approx 0.05 \times (TL + TM)$	TVA (References 7-15, 7-16)
Utilities Facilities, UF	$UF = 0.03 \times (TL + TM)$	TVA (References 7-15, 7-16)
Construction Field Expense, CFE	$CFE \approx 0.13 \times (TL + TM + CF + SF + UF) = 0.13 \times DI$	TVA (References 7-15, 7-16)
Contractor's Fee, CON	$CON \approx 0.07 \times DI$	TVA (References 7-15, 7-16)
Construction Contingency, CTN	$CTN \approx 0.11 \times DI$	TVA (References 7-15, 7-16)
Initial Charges, IC	IC from input data (e.g., licensing fees, usually none)	This report, Section 7.3
Startup Costs, SC	$SC = 0.10 \times (DI + DS + EFEE + CFE + CON + CTN)$ $= 0.10 \times (DI + IND)$	TVA (References 7-15, 7-16)
Indirect Operating Costs, IOC(n)	$IOC(n) = CC(n) + CCLOST(n) + OH$	
Capital Charge, CC(n)	$CC(n) = D + IN + RE + CCT(n)$	
Depreciation, D	$D = II/N$	Straight line depreciation
Insurance, IN	$IN = 0.005 \times II$	TVA (References 7-15, 7-16)
Replacements, RE	$RE = 0.004 \times II$	
Cost of Capital and Taxes, CCT(n)	$CCT(n) = \left[ib + r(1 - b) + \frac{t}{1 - t}(1 - b)r\right] \cdot ODB(n)$ where t = effective tax rate $= s + (1-s)f$ and s = state tax rate f = federal tax rate and $ODB = II - (n-1)D$	This report, Section 7.2

[a] A glossary of cost analysis terms appears in Appendix E.

TABLE 7-6. Concluded

Cost Factor	Calculation Equation	Reference
Capital charges of Lost Capacity, CCLOST (n)	Calculated analogously to CC(n), only use $\left(\mathrm{IIO} \times \frac{\mathrm{DRATE}}{\mathrm{KW}}\right)$ in place of II where IIO = Initial investment of boiler DRATE = Power derate with controls, if necessary KW = Power rating of boiler before control	This report, Section 7.2
Overhead		
Administrative overhead, OHA	OHA = 0.10 x OLS	TVA (References 7-15, 7-16)
Plant overhead, OHP	OHP = 0.20 x (OLS + UC + M + A), as indicated below	TVA (References 7-15, 7-16)
Direct Operating Costs, DOC		
Fuel Penalty, AF	AF = HYR x HRATE x (KW - DRATE) x FCOST x FPEN where HYR = Annual operating hours	Engineering estimate[a]
Fuel Credit, FC	FC = HYR x HRATE x DRATE x FCOST	Engineering estimate
Raw materials, RM	RM from input data where HRATE = Heat rate of boiler FCOST = Fuel cost	Engineering estimate
Conversions Costs		
Additional operating personnel, OLS	OLS from engineering estimate	Reference 7-4
Additional utilities, UC	UC from engineering estimate	
Additional maintenance, M	M ≈ 0.05 x (TL + TM)	TVA (References 7-15, 7-16)
Required analyses, A	A from engineering estimate	Reference 7-4
Annual royalties, AROY	AROY from input data	Reference 7-4
Purchased Power, PP	PP = DRATE x HYR x PPR where PPR = purchased power rate	Engineering estimate
Annualized Cost to Control, ARRU	$\mathrm{ARRU} = \frac{j(1+j)^N}{(1+j)^N-1}\left[\sum_{n=1}^{N} \frac{\mathrm{DOC} + \mathrm{IOC}(n)}{(1+j)^n}\right] \cdot \frac{1}{(\mathrm{KW} - \mathrm{DRATE})}$	This report, Section 7.2

[a] Engineering estimates are based on process analyses in Section 6, and design analyses in Section 7.3.

The calculation equations of Table 7-6 are self-explanatory, but perhaps a few comments are in order. The cost of capital and taxes per year can be calculated as follows:

$$\text{Taxable Income} = (\text{Return to Equity}) + \overset{\text{Tax Deductible}}{(\text{Interest on Borrowed Money})}$$

$$+ \overset{\text{Tax Deductible}}{(\text{Depreciation})} + (\text{Money for Taxes})$$

Now the total tax, T, is given by:

$$\begin{aligned} T &= \text{Federal} + \text{State Tax} \\ &= t \times (\text{Taxable Income}) \end{aligned}$$

where t = effective tax rate
$= s + (1 - s)f$
s = State tax rate
f = Federal tax rate

since State taxes are deductible from Federal taxes.

Combining the equations,

$$\begin{aligned} T &= \frac{t}{1 - t} (\text{Return to Equity}) \\ &= \frac{t}{1 - t} (1 - b)r \cdot \mathrm{ODB}(n) \end{aligned}$$

where the outstanding depreciation base ODB(n) in year n is given by:

$$\begin{aligned} \mathrm{ODB}(n) &= II - \sum_{n=1}^{n} D(n) \\ &= II - (n - 1)D \end{aligned}$$

assuming straight line depreciation.

Therefore, the cost of capital and taxes in year n is given by:

$$CCT(n) = \left[ib + r(1 - b) + \frac{t}{1 - t}(1 - b)r\right] \cdot ODB(n)$$

and should be annualized as:

$$ACCT = \frac{j(1 + j)^N}{(1 + j)^N - 1} \cdot \left[\sum_{n=1}^{N} \frac{CCT(n)}{(1 + j)^n}\right]$$

Another point of note in the cost analysis is the accounting of lost capacity if a utility boiler is forced to derate due to the controls implemented and the utility cannot compensate elsewhere for the lost power. For example, if a utility is forced to apply BOOS as a control technique on a coal-fired boiler, the unit may have to be derated by as much as 20 percent. The cost of purchased power to make up their lost capacity, less any savings from unused fuel (due to derating of the boiler), should be charged to the cost of that control. Furthermore, the control technique should be held accountable for a prorated portion of the capital charge of the original boiler based on the fractional loss in boiler capacity, i.e.,

$$\left(\frac{\text{Annual Capital Charge}}{\text{of Lost Capacity}}\right) = \left(\frac{\text{Annual Capital Charge}}{\text{of Boiler}}\right) \times \left(\frac{\text{Lost Capacity}}{\text{Orig. Total Capacity}}\right)$$

7.3 RETROFIT CONTROL COSTS

Representative costs for retrofitting and operating typical existing boilers under NO_x control are presented in this section. Costs are given in dollars per unit electrical output per operating year. As shown in Section 7.1, on a per unit kW basis, average control costs are not a strong function of unit size, but rather strongly dependent on the characteristics of the particular unit in question. Still, for the purposes of this cost analysis, typical unit sizes are chosen in Section 7.3.1. Appropriate representative controls are also selected. Section 7.3.2 goes into the details of control equipment hardware and operating costs, while Section 7.3.3 gives the results of annualizing the cost to control.

7.3.1 Selection of Representative Boilers

The three major utility boiler firing designs (tangential, single wall, and horizontally opposed wall firing) and the three primary fuels (coal, oil, and natural gas), give nine basic boiler/fuel classifications. Of course, many units are designed to burn more than one fuel. This is particularly true for gas and oil fuels.

The Environmental Protection Agency's Energy Data System (Reference 7-21) was used to obtain relative installed population size distributions of the nine boiler/fuel classifications. Using this system, a typical unit size was determined for each category. Further comparisons were then made to determine which cases would be examined in more detail in retrofit design studies.

The cases selected for further study were a tangential coal-fired unit to power a 225 MW turbine generator, a 540 MW horizontally opposed coal-fired unit, and a 90 MW front wall gas- and oil-fired unit. Primary considerations in making these selections included:

- The trend toward coal firing, particularly in larger size units, emphasizes tangential and horizontally opposed firing designs
- Many units are capable of burning oil and gas, especially in the smaller size ranges. Single wall (front or rear) fired units are common in this application

The methods used to control NO_x emissions are fuel dependent. In retrofit applications, the number of control methods available may be limited. The discussion of control techniques in Sections 4 through 6 addressed the limitations of the various control methods. It was noted that the retrofit application of NO_x controls can impose serious operating problems on the user in that the control methods often cause a significant departure from the original design operating characteristics of the unit (References 7-8 and 7-23). Noting that control needs, and therefore, control costs are more dependent on the fuel fired than on the boiler equipment type, the following typical boilers and controls were chosen for detailed analysis:

Boiler/Fuel Type	NO_x Control
Tangential/Coal	OFA
Opposed Wall/Coal	OFA
Opposed Wall/Coal	Low NO_x Burners
Opposed Wall/Coal	BOOS
Single Wall/Oil and Gas	BOOS
Single Wall/Oil and Gas	OFA and FGR

Overfire air and low NO_x burners were selected as the retrofit control methods for coal firing. Burners out of service is not necessarily recommended for coal-fired units, but is included to demonstrate the prohibitively high cost of derating a unit, as is often the case for pulverized coal units. Burners out of service, and flue gas recirculation through the burners combined with overfire air were selected as the retrofit control methods for the single wall oil- and gas-fired unit. These methods have been shown to be effective in retrofit applications, as discussed earlier in this report.

7.3.2 Retrofit Design Analysis

In the retrofit design analysis, three representative units were selected, retrofit NO_x controls were chosen, and estimates of labor, materials, and equipment required to install the NO_x control equipment were performed.

Using the aforementioned Energy Data System (Reference 7-21), a listing for each fuel and firing type of boiler was obtained. A weighted average of unit capacity was then used to select a typical unit capacity. This size and firing arrangement was then approximated and used as the basis for the design study. It should be noted that in the design of a boiler, there are many variables to be considered. There are no "standard" utility boilers.

7.3.2.1 Tangential Coal

A 225 MW unit was selected as a representative tangential pulverized coal-fired unit with overfire air selected as the retrofit NO_x control technique. The model used for the study was a single furnace design with five levels of burners or fuel admission nozzles, one set per corner. With a plant cycle efficiency of 37.1 percent (9.71 MJ/kWh or 9200 Btu/kWh heat rate), a heat input rate per nozzle of 30 MW (1.02×10^8 Btu/hr) would be required. The design excess air at full load was assumed to be 20 percent. The overfire air ports were designed to handle a maximum of 20 percent of the total airflow.

It was assumed that there were no major obstructions in routing the ductwork from the hot combustion air (secondary air) duct to the overfire air ports. It was also assumed that there were no major problems with access to the work areas. It should be noted that in retrofit installations, problems with obstructions and access are frequently encountered. These problems can increase installation and material costs significantly.

The cost estimates were based on vendor quotes and engineering estimates. Installation costs were based on the Richardson Rapid Method (Reference 7-22) and assumed an average labor rate for a composite crew of $15.30/hr. These estimates are listed in Tables 7-7 through 7-9. It will be noted that in these and subsequent analogous tables, numbers presented have not been rounded off in order to minimize errors in the cost code calculations. Obviously, they should be taken to only two significant figures. The final control costs presented in Section 7.3.3 have been rounded to two significant figures. Drawings of the tangential coal model for the design study are shown in Figures 7-3 through 7-5. A discussion of annualized retrofit control costs including investment and operating costs is given in Section 7.3.3.

7.3.2.2 Opposed Wall Coal

A 540 MW opposed wall coal-fired boiler was selected as a representative unit. Overfire air was selected as the retrofit NO_x control technique as in the tangential coal design. The model used for the study was a single furnace design with 48 burners, 24 on the front wall and 24 on the rear wall. The burners were arranged in four horizontal rows of six burners each. With a plant cycle efficiency of 37.1 percent (9.71 MJ/kWh or 9200 Btu/kWh heat rate), a heat input rate per burner of 30.4 MW (1.03×10^8 Btu/hr) would be required. The overfire air ports were designed to handle 20 percent of the total airflow. The excess air level at full load was assumed to be 15 percent.

TABLE 7-7. COMPONENT COST ESTIMATE: RETROFIT OFA FOR TANGENTIAL COAL-FIRED BOILER (1977 DOLLARS)

Component Description and Quantity Required	Type of Quote	Amount ($)
Expansion Joints, 38" x 72" x 12" Eight Required	WQ[a]	13,312
Control Dampers, 38" x 72" Four Required	WQ[b]	5,060
Tilting Air Nozzles, 28" x 16" Eight Required	WQ[b]	6,760
Hot Air Duct 38" x 72" x 120" Four Required	WQ[b]	5,760
Materials (Tubes, Fittings and Supports)	EE	1,339
Total Component Cost		31,903

[a] Tate-Reynolds Co., Inc.

[b] Kanawha Manufacturing Co.

WQ -- Written quote

EE -- Engineering estimate

TABLE 7-8. INSTALLATION COST ESTIMATE: RETROFIT OFA FOR TANGENTIAL COAL-FIRED BOILER (1977 DOLLARS)

Component Installed	Estimated Hours	Cost Estimate @ $15.30/hr
Overfire Air Ports	2965	45,362
Ducts, Expansion Joints, and Dampers	565	8,647
Total Installation Estimate	3530	54,009

TABLE 7-9. RETROFIT OFA FOR TANGENTIAL COAL-FIRED BOILER (1977 DOLLARS)

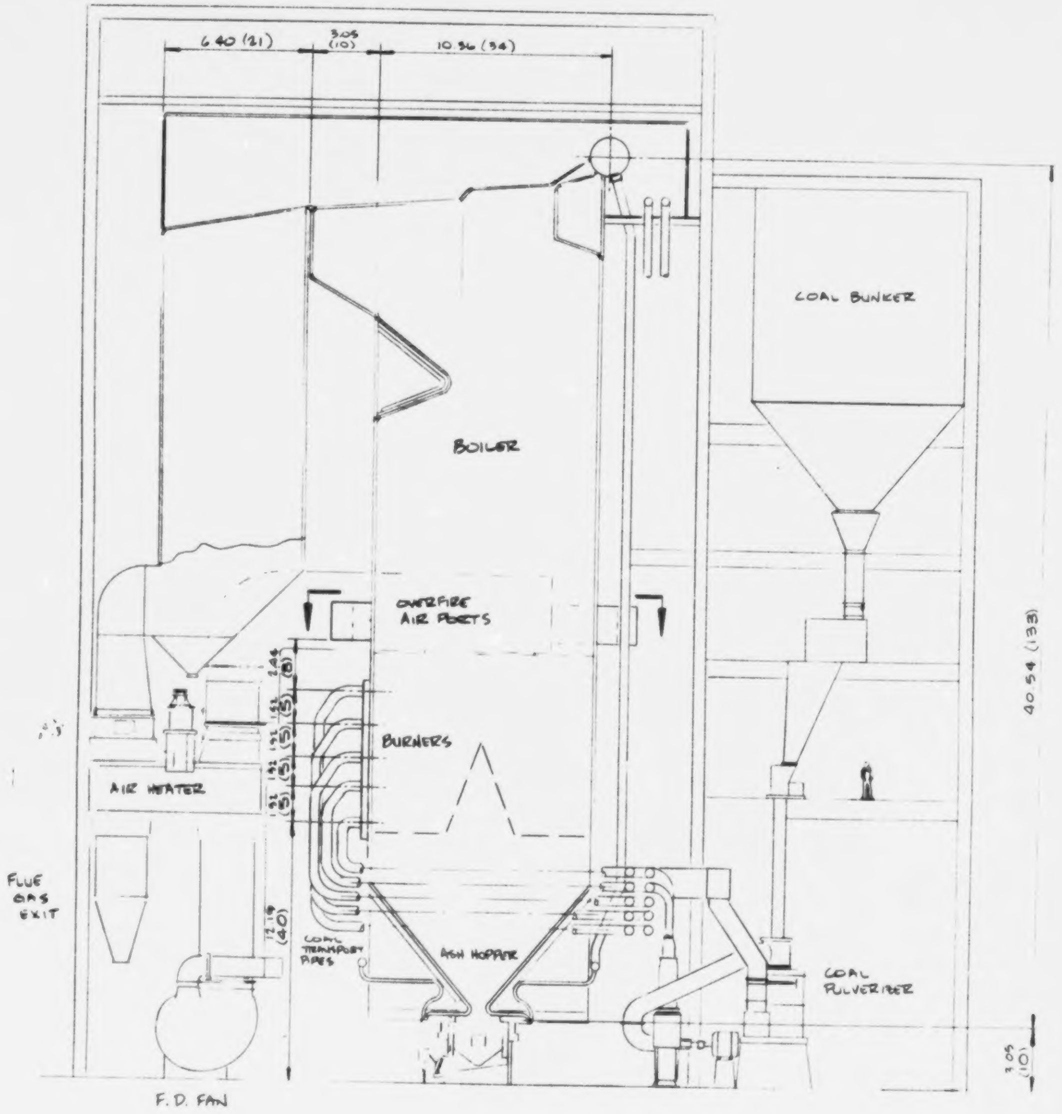
I. Design Estimate

Category	Estimated Hours	Estimated Costs
1. Designer @ $9/hr	600	5,400
2. Engineer @ $12/hr	240	2,880
3. Supervision @ 10% of 1 and 2		828
4. Overhead @ 110% of 1, 2, and 3		10,019
5. General and Administrative @ 25% of 1, 2, 3, and 4		4,782
6. Fee @ 8% of 1, 2, 3, 4, and 5		1,913
		25,822

II. Construction Estimate

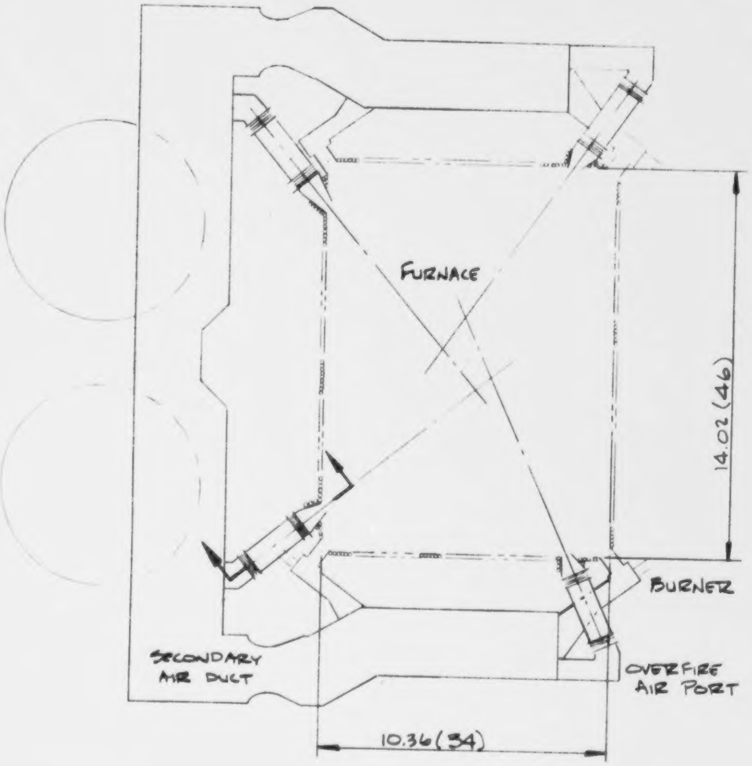
Category	Estimated Hours	Estimated Cost
1. Labor @ $15.30/hr (Table 7-8)	3530	54,009
2. Supervision @ 10% of 1		5,401
3. General and Administrative @ 25% of 1 and 2		14,852
4. Construction Field Expense		15,651
5. Contractor's Fee		8,427
6. Construction Contingency		13,243
7. Construction Facilities		5,733
8. Service Facilities		5,308
9. Utilities Facilities		3,185
		125,809

III. Component Cost Estimate (Table 7-7)	31,903
Subtotal (I + II + III)	183,534
Startup Costs @ 10% of I, II, & III	18,353
Total Initial Investment	201,887


6.40 (21)
3.05 (10)
10.36 (34)
BOILER
COAL BUNKER
OVERFIRE AIR PORTS
2.44 (8)
1.52 (5)
1.52 (5)
1.52 (5)
1.52 (5)
BURNERS
AIR HEATER
FLUE GAS EXIT
12.19 (40)
COAL TRANSPORT PIPES
ASH HOPPER
COAL PULVERIZER
40.54 (133)
3.05 (10)
F. D. FAN

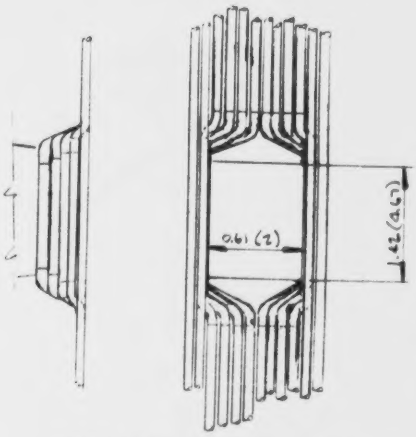
DIMENSIONS IN METERS (FEET)

Figure 7-3. Retrofit overfire air for typical tangential coal-fired boilers.


FURNACE
14.02 (46)
BURNER
SECONDARY AIR DUCT
OVERFIRE AIR PORT
10.36 (34)

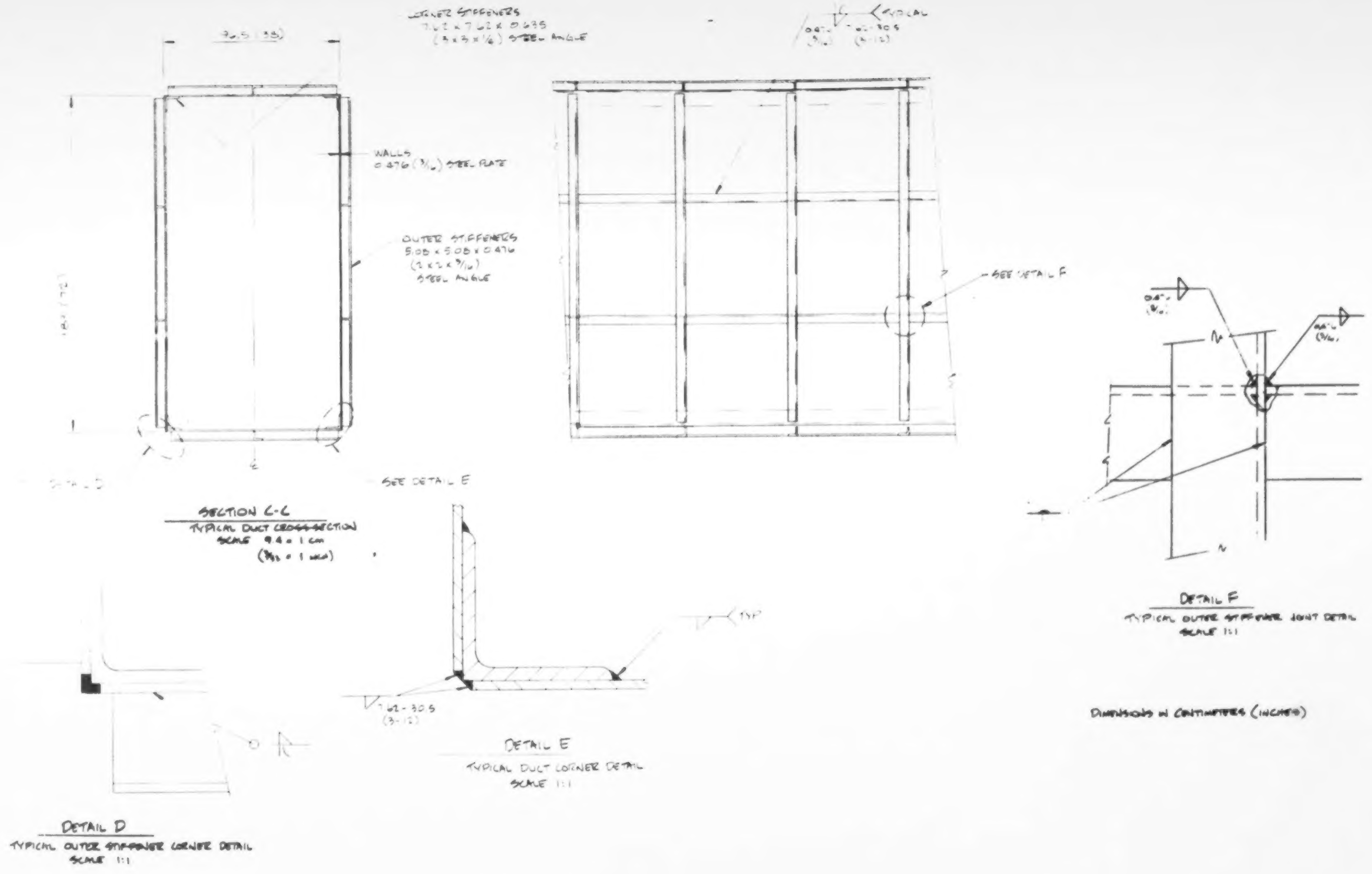
FURNACE PLAN VIEW

DIMENSIONS IN METERS (FEET)


0.61 (2)
1.42 (4.67)

OVERFIRE AIR PORT DETAIL

Figure 7-4. Typical overfire air port arrangement for tangential coal-fired boilers.



CORNER STIFFENERS
7.62 x 7.62 x 0.635
(3 x 3 x 1/4) STEEL ANGLE
76.5 (33)
0.476 (3/16)
7.62-30.5 (3-12)
TYPICAL
WALLS
0.476 (3/16) STEEL PLATE
OUTER STIFFENERS
5.08 x 5.08 x 0.476
(2 x 2 x 3/16)
STEEL ANGLE
SEE DETAIL F
DETAIL D
SEE DETAIL E
SECTION C-C
TYPICAL DUCT CROSS-SECTION
SCALE 9.4 = 1 cm
(3/32 = 1 inch)
TYP
7.62-30.5
(3-12)
DETAIL E
TYPICAL DUCT CORNER DETAIL
SCALE 1:1
DETAIL D
TYPICAL OUTER STIFFENER CORNER DETAIL
SCALE 1:1
DETAIL F
TYPICAL OUTER STIFFENER JOINT DETAIL
SCALE 1:1
DIMENSIONS IN CENTIMETERS (INCHES)

Figure 7-5. Typical OFA duct detail for tangential coal-fired boilers.

Twelve overfire air ports were added, one port above each vertical row of burners. It was assumed that there were no major obstructions in routing the necessary ductwork. The ducts were attached as simple extensions to the front and rear windboxes. It was also assumed that there would be no major problems with access to the work areas. It should be noted that in retrofit installations, access and obstruction problems are frequently encountered. These factors may increase installation and material costs significantly.

Component and installation costs were estimated as described in Section 7.3.2.1. These estimates are listed in Tables 7-10 through 7-12. Drawings of the opposed wall coal-fired model boiler for the design study are shown in Figure 7-6. A discussion of annualized retrofit control costs including investment and operating costs is given in Section 7.3.3.

The retrofit installation of low NO_x burners on this opposed wall coal-fired unit was also considered. It was assumed that low NO_x burners could be installed in place of the existing burners with no modifications to burner openings in the furnace walls. It was also assumed that existing coal conveying equipment, flame safeguard equipment, burner register drives, and igniting equipment could be utilized. The assumptions of good access and few obstructions cannot be justified here. To remove and replace the burners, the burner front piping and portions of the windbox would have to be removed for access. Considering these factors, the cost estimates for the retrofit installation of low NO_x burners is shown in Tables 7-13 through 7-15.

7.3.2.3 Single Wall Oil and Gas

A single wall unit designed to fire both oil and gas was selected because many units are capable of burning either fuel. Also, the same retrofit NO_x control techniques are effective with either fuel. A representative unit size of 90 MW was chosen. The model used for the study was a single furnace design with six burners on the front wall arranged in two rows of three burners each. With a plant cycle efficiency of 37 percent (9.71 MJ/kWh or 9200 Btu/kWh), a heat input rate per burner of approximately 40.5 MW (1.38 x 10^8 Btu/hr) would be required.

The retrofit NO_x control cases chosen were (1) burners out of service, and (2) flue gas recirculation through the burners combined with overfire air. These control methods are effective for both gas- and

TABLE 7-10. COMPONENT COST ESTIMATE: RETROFIT OFA FOR OPPOSED WALL COAL-FIRED BOILER (1977 DOLLARS)

Component Description and Quantity Required	Type of Quote	Amount ($)
Expansion Joints, 36" Diameter Twelve Required	WQ[a]	21,156
Segmented Elbows, 36" Diameter Twelve Required	WQ[b]	14,340
Round to Square Transitions Twelve Required	WQ[b]	13,296
Control Dampers, 48" x 48" Twelve Required	WQ[b]	15,348
Materials (Tubes, Fittings, Supports)	EE	1,933
Total Component Cost		66,073

[a] Tate-Reynolds Co., Inc.

[b] Kanawha Manufacturing Co.

WQ -- Written Quote

EE -- Engineering Estimate

TABLE 7-11. INSTALLATION COST ESTIMATE: RETROFIT OFA FOR OPPOSED WALL COAL-FIRED BOILER (1977 DOLLARS)

Component Installed	Estimated Hours	Cost Estimate @ $15.30/hr
Overfire Air Ports	3523	53,898
Ducts, Expansion Joints, and Dampers	2090	31,975
Total Installation Estimate	5613	85,873

TABLE 7-12. INITIAL INVESTMENT ESTIMATE: RETROFIT OFA FOR OPPOSED WALL COAL-FIRED BOILER (1977 DOLLARS)

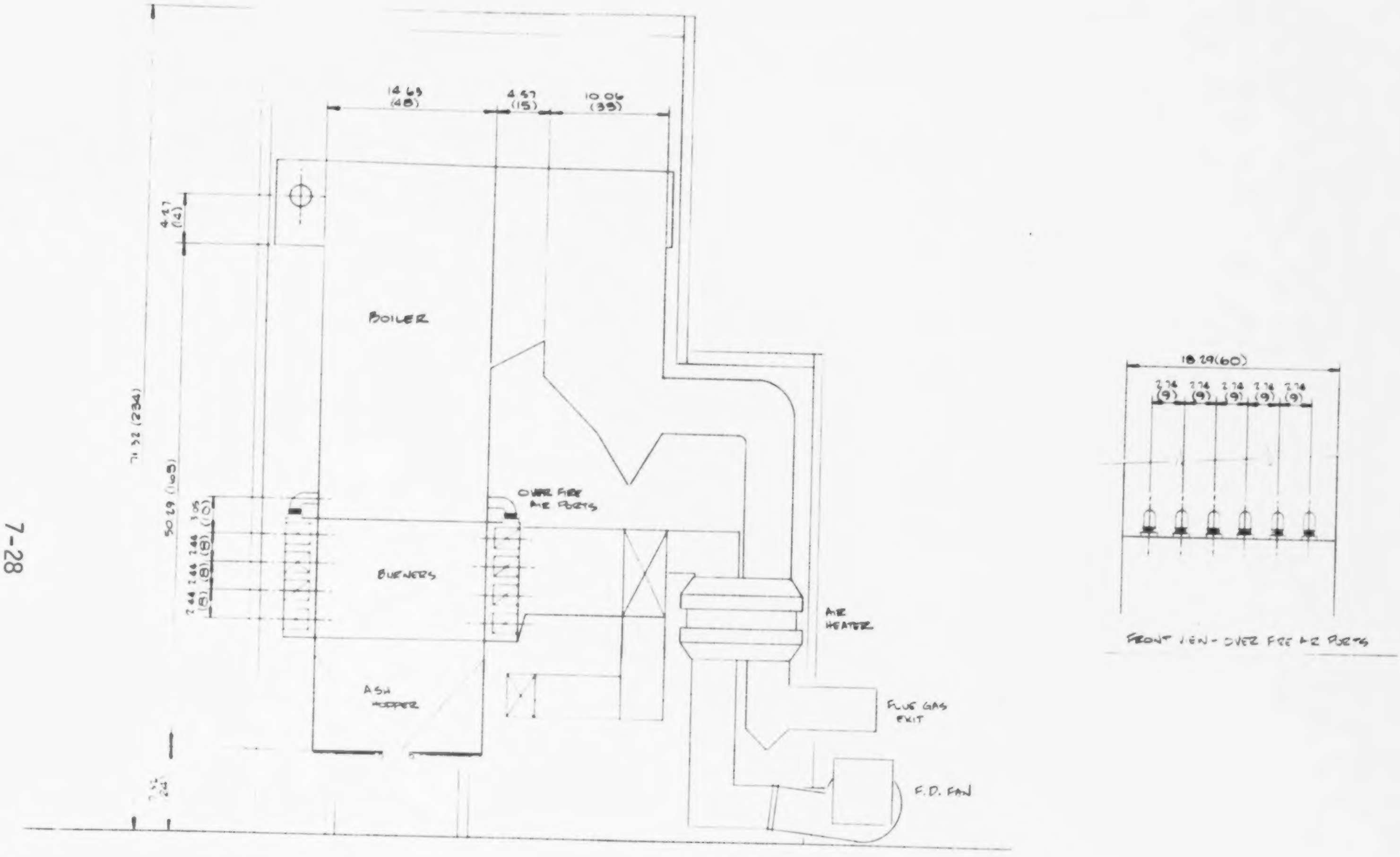
I. Design Estimate

Category	Estimated Hours	Estimated Cost
1. Designer @ $9/hr	700	6,300
2. Engineer @ $12/hr	300	3,600
3. Supervision @ 10% of 1 and 2		990
4. Overhead @ 110% of 1, 2, and 3		11,979
5. General and Administrative @ 25% of 1, 2, 3, and 4		5,717
6. Fee @ 8% of 1, 2, 3, 4, and 5		2,287
		30,873

II. Construction Estimate

Category	Estimated Hours	Estimated Cost
1. Labor @ $15.30/hr (Table 7-11)	5613	85,879
2. Supervision @ 10% of 1		8,588
3. General and Administrative @ 25% of 1 and 2		23,617
4. Construction Field Expense		27,148
5. Contractor's Fee		14,618
6. Construction Contingency		22,972
7. Construction Facilities		9,944
8. Service Facilities		9,208
9. Utilities Facilities		5,525
		207,499

III. Component Cost Estimate (Table 7-10)	66,073
Subtotal (I + II + III)	304,445
Startup Costs @ 10% of I, II, & III	30,444
Total Initial Investment	334,889


14.63
(48)
4.57
(15)
10.06
(33)
4.27
(14)
71.32 (234)
50.29 (165)
2.44 2.44 2.44 3.05
(8) (8) (8) (10)
7.32
24
BOILER
OVER FIRE
AIR PORTS
BURNERS
ASH
HOPPER
AIR
HEATER
FLUE GAS
EXIT
F.D. FAN
18.29 (60)
2.74 2.74 2.74 2.74 2.74
(9) (9) (9) (9) (9)
FRONT VIEW - OVER FIRE AIR PORTS

DIMENSIONS IN METERS (FEET)

Figure 7-6. Retrofit overfire air for typical opposed wall coal-fired boilers.

TABLE 7-13. COMPONENT ESTIMATE: RETROFIT LOW NO_x BURNERS FOR OPPOSED WALL COAL-FIRED BOILER (1977 DOLLARS)

Component Description and Quantity Required	Type of Quote	Amount ($)
Low NO_x Burner, Complete 48 Required	EE	336,000

EE -- Engineering estimate based on discussion with equipment manufacturer.

TABLE 7-14. INSTALLATION COST ESTIMATE: RETROFIT LOW NO_x BURNERS FOR OPPOSED WALL COAL-FIRED BOILER (1977 DOLLARS)

Component Installed	Estimated Hours	Cost Estimate @ $15.30/hr
Low NO_x Burners	15,360	235,008

TABLE 7-15. INITIAL INVESTMENT ESTIMATE: RETROFIT LOW NO_x BURNERS FOR OPPOSED WALL COAL-FIRED BOILER (1977 DOLLARS)

I. Design Estimate

Category	Estimated Hours	Estimated Cost
1. Designer @ $9/hr	400	3,600
2. Engineer @ $12/hr	150	1,800
3. Supervision @ 10% of 1 and 2		540
4. Overhead @ 110% of 1, 2, and 3		6,534
5. General and Administrative @ 25% of 1, 2, 3, and 4		3,119
6. Fee @ 8% of 1, 2, 3, 4, and 5		1,247
		16,840

II. Construction Estimate

Category	Estimated Hours	Estimated Cost
1. Labor @ $15.30/hr (Table 7-14)	15,360	235,008
2. Supervision @ 10% of 1		23,501
3. General and Administrative @ 25% of 1 and 2		64,627
4. Construction Field Expense		97,170
5. Contractor's Fee		52,322
6. Construction Contingency		82,221
7. Construction Facilities		35,593
8. Service Facilities		32,957
9. Utilities Facilities		19,774
		643,173

III. Component Cost Estimate (Table 7-13)	336,000
Subtotal (I + II + III)	996,013
Startup Costs @ 10% of I, II, & III	99,601
Total Initial Investment	1,095,614

oil-fired units. The overfire air ports were designed for 25 percent of the total air and recirculated gas flow. The flue gas recirculation system was designed to handle 25 percent of the flue gas normally produced. Recirculating this flue gas into the burner windbox results in a minimum windbox O_2 level of approximately 17 percent.

Three overfire air ports were added, one port above each vertical row of burners. Again, it was assumed that there were no major obstructions in routing the necessary ductwork. The ducts were attached as simple extensions to the windbox. The flue gas recirculation system was similarly added. It was further assumed that there was reasonable access to the work areas. As noted in Section 7.3.2.1 and 7.3.2.2, access and obstruction problems are frequently encountered and have the effect of increasing installation and material costs significantly. Other assumptions were that there was adequate forced draft fan capacity and that ductwork and furnace strength were adequate with the addition of gas recirculation.

Component and installation cost estimates using the methods described in Section 7.3.2.1 are listed in Tables 7-16 through 7-18. Drawings of the single wall unit used in the study are shown in Figure 7-7. A discussion of annualized retrofit control costs including investment and operating costs is given in Section 7.3.3.

7.3.3 Annualized Retrofit Control Costs

Based on the retrofit control design analysis of Sections 7.3.2, and the assumptions made in the cost analysis algorithm of Section 7.2, typical retrofit control costs were generated. The results based on 1977 dollars are given in detail in Tables 7-19 through 7-24. It is assumed here that low excess air represents standard operating procedure. As discussed in Section 7.1, any investment costs for this control are usually offset by savings in operating efficiency.

It was assumed that all retrofit installations could be completed during normal outage periods, and hence downtime need not be costed. As shown in Section 7.3.2, this assumption is a good one (installation time 6 weeks or less) for all the retrofit cases considered with the exception of low NO_x burner installation. For low NO_x burner retrofit, which is estimated to require 12 weeks, installation will have to be scheduled during a major overhaul of the boiler.

TABLE 7-16. COMPONENT COST ESTIMATE: RETROFIT OFA AND FGR FOR TYPICAL SINGLE WALL OIL- AND GAS-FIRED BOILER (1977 DOLLARS)

Component Description and Quantity Required	Type of Quote	Amount ($)
Flue Gas Recirculating Fan, Housing, Motor, Turning Gear, Switchgear, Inlet Damper	VQ[a]	110,000
Controls and Instrumentation	VQ[b]	14,495
Expansion Joints, FGR Ducts Five Required	EE	8,320
Dampers, FGR Ducts Three Required	EE	3,837
Segmented Elbows, 36" Diameter, OFA Three Required	WQ[c]	3,585
Expansion Joints, 36" Diameter, OFA Three Required	WQ[d]	5,289
Round to Square Transitions, OFA Three Required	WQ[c]	3,324
Control Dampers, 48" x 48", OFA Three Required	WQ	3,837
Materials (Tubes, Fittings, Supports, Concrete, Reinforcing)	EE	4,165
Ductwork	EE	38,002
Total Component Cost		194,854

[a] Westinghouse, Sturtevant Div.

[b] Bailey Controls Co.

[c] Kanawha Mfg. Co.

[d] Tate Reynolds Co. Inc.

VQ -- Verbal Quote

WQ -- Written Quote

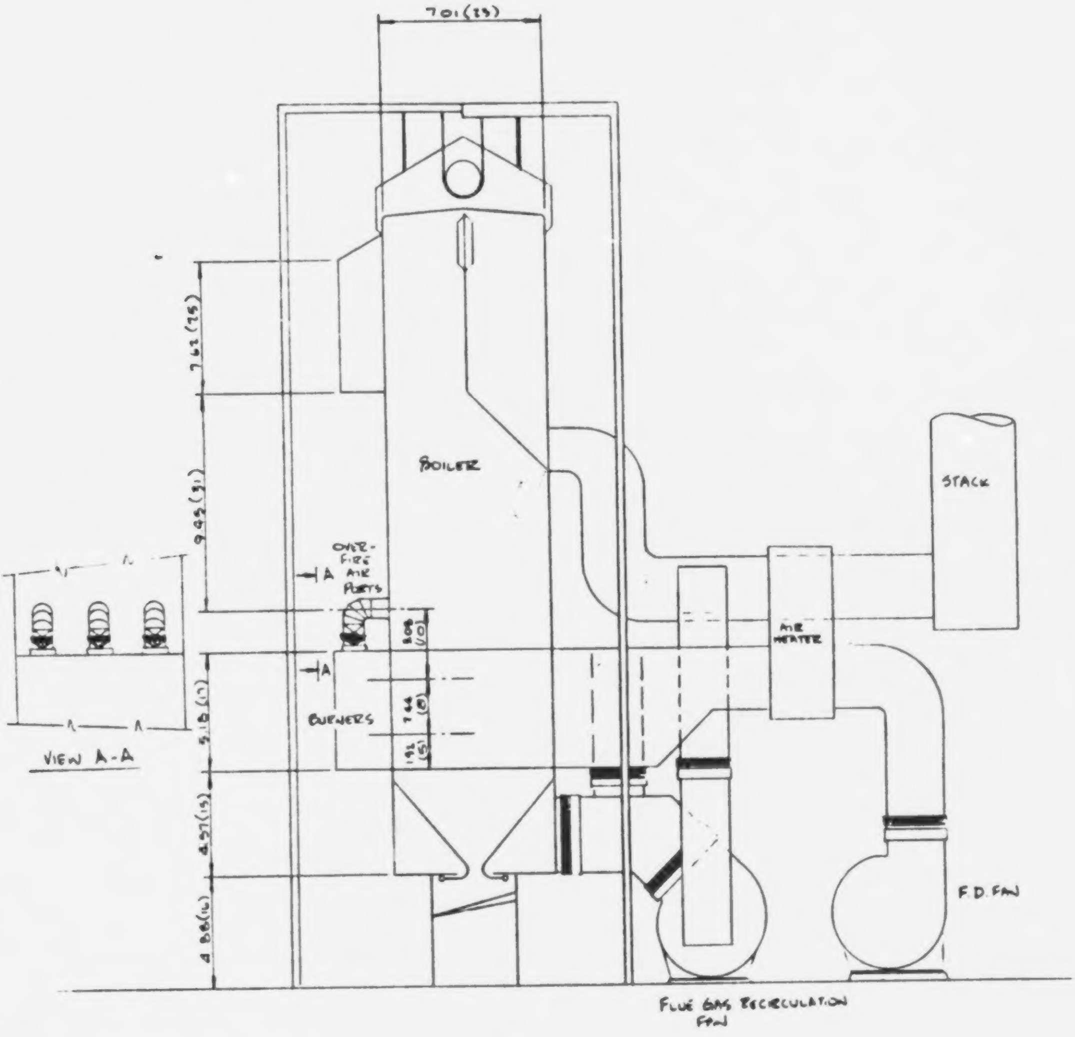
EE -- Engineering Estimate

TABLE 7-17. INSTALLATION COST ESTIMATE: RETROFIT OFA AND FGR FOR TYPICAL SINGLE WALL OIL- AND GAS-FIRED BOILER (1977 DOLLARS)

Component Installed	Estimated Hours	Cost Estimate @ $15.30/hr
Overfire Air Ports	1166	17,835
OFA Ducts, Expansion Joints, and Dampers	934	14,285
FGR Fan Foundation	45	5,280
FGR Fan and Motor	304	4,651
FGR Ductwork, Dampers, Expansion Joints	1863	28,502
Crane Rental	--	2,500
Total Installation Estimate	4612	73,053

TABLE 7-18. INITIAL INVESTMENT ESTIMATE: RETROFIT OFA AND FGR FOR TYPICAL SINGLE WALL OIL- AND GAS-FIRED BOILER (1977 DOLLARS)

	Category	Estimated Hours	Estimated Cost
I.	Design Estimate		
	1. Designer @ $9/hr	800	7,200
	2. Engineer @ $12/hr	290	3,480
	3. Supervsion @ 10% of 1 and 2		1,068
	4. Overhead @ 110% of 1, 2, and 3		12,923
	5. General and Administrative @ 25% of 1, 2, 3, and 4		6,168
	6. Fee @ 8% of 1, 2, 3, 4, and 5		2,467
			33,306
II.	Construction Estimate		
	1. Labor @ $15.30/hr (Table 7-17)	4,612	70,564
	2. Supervision @ 10% of 1		7,056
	3. General and Administrative @ 25% of 1 and 2		19,405
	4. Construction Field Expense		43,028
	5. Contractor's Fee		23,169
	6. Construction Contingency		36,408
	7. Construction Facilities		15,761
	8. Service Facilities		14,594
	9. Utilities Facilities		8,756
			238,741
III.	Component Cost Estimate (Table 7-16)		194,854
	Subtotal (I + II + III)		466,901
	Startup Costs @ 10% of I, II, & III		46,690
	Total Initial Investment		513,591


7.01 (23)
7.62 (25)
9.45 (31)
5.18 (17)
4.57 (15)
4.88 (16)
3.05 (10)
2.44 (8)
1.52 (5)
BOILER
STACK
AIR HEATER
F.D. FAN
FLUE GAS RECIRCULATION FAN
OVER-FIRE AIR PORTS
BURNERS
A
A
VIEW A-A

DIMENSIONS IN METERS (FEET)

Figure 7-7. Retrofit OFA and FGR for typical single wall oil- and gas-fired boilers.

TABLE 7-19. RETROFIT CONTROL COST: OVERFIRE AIR FOR EXISTING TANGENTIAL COAL-FIRED BOILER (1977 DOLLARS)

```
MAXIMUM CONTINUOUS RATING (MW) :     225.
TYPICAL BASELINE NOX EMISSION (PPM AT 3% O2)   :      455.
TYPICAL CONTROLLED NOX EMISSION (PPM AT 3% O2) :      310.

DERATE REQUIRED (MW)    : NONE

FUEL PENALTY (PERCENT) :     .00

ANNUALIZED LOST CAPACITY CAPITAL CHARGE ($/KW-YR) : NONE

ANNUALIZED PURCHASED POWER PENALTY ($/KW-YH) : NONE

INITIAL INVESTMENT ($/KW) :     .90

ANNUALIZED INDIRECT OPERATING COST ($/KW-YR) :     .21

ANNUALIZED   DIRECT OPERATING COST ($/KW-YR) :     .32

ANNUALIZED COST TO CONTROL ($/KW-YR) :     .53
------------------------------------------------------------------------------------
           INITIAL INVESTMENT ($)

   ENGINEERING DESIGN & SUPERVISION                          23908.
   ENGINEERING FEE                                            1913.

   HARDWARE                                                  31903.
   INSTALLATION LABOR & SUPERVISION                          74262.
   CONSTRUCTION FACILITIES                                    5733.
   SERVICE FACILITIES                                         5308.
   UTILITIES FACILITIES                                       3185.

   CONSTRUCTION FIELD EXPENSE                                15651.
   CONTRACTORS FEE                                            8427.
   CONSTRUCTION CONTINGENCY                                  13243.

   INITIAL CHARGES                                               0.
   STARTUP COSTS                                             18353.
 -----------------------------------------              ----------
 TOTAL INITIAL INVESTMENT                                   201087.
------------------------------------------------------------------------------------
           ANNUALIZED OPERATING COST ($/YR)

 INDIRECT OPERATING COSTS

   CAPITAL CHARGES
      DEPRECIATION                                            8075.
      INSURANCE                                               1009.
      REPLACEMENT COSTS                                        808.
      COST OF CAPITAL & TAXES                                23055.

   CAPITAL CHARGES OF LOST CAPACITY (IF DERATE)
      DEPRECIATION                                               0.
      INSURANCE                                                  0.
      REPLACEMENT COSTS                                          0.
      COST OF CAPITAL & TAXES                                    0.

   OVERHEAD
      ADMINISTRATIVE OVERHEAD                                    0.
      PLANT OVERHEAD                                         14432.

 DIRECT OPERATING COSTS

   FUEL COST PENALTY                                             0.
   FUEL CREDIT (FOR UNUSED FUEL IF DERATE)      (                0.)
   RAW MATERIALS                                                 0.
   CONVERSION COSTS
      ADDITIONAL OPERATING PERSONNEL                             0.
      ADDITIONAL UTILITIES REQUIREMENTS                      66850.
      ADDITIONAL MAINTENANCE                                  5308.
      REQUIRED ANALYSES                                          0.
   ANNUAL ROYALTIES                                              0.
   PURCHASED POWER (IF DERATE)                                   0.
 -----------------------------------------              ----------
 TOTAL ANNUALIZED OPERATING COSTS                           119538.
------------------------------------------------------------------------------------
 ANNUALIZED COST TO CONTROL ($/KW-YR)                           .53
```

TABLE 7-20. RETROFIT CONTROL COST: OVERFIRE AIR FROM EXISTING OPPOSED WALL COAL-FIRED BOILER (1977 DOLLARS)

```
        MAXIMUM CONTINUOUS RATING (MW) :      540.
        TYPICAL BASELINE NOX EMISSION (PPM AT 3% O2)   :      785.
        TYPICAL CONTROLLED NOX EMISSION (PPM AT 3% O2) :      550.

        DERATE REQUIRED (MW)    : NONE

        FUEL PENALTY (PERCENT) :     .25

        ANNUALIZED LOST CAPACITY CAPITAL CHARGE ($/KW-YR) : NONE

        ANNUALIZED PURCHASED POWER PENALTY ($/KW-YR) : NONE

        INITIAL INVESTMENT ($/KW) :     .62

        ANNUALIZED INDIRECT OPERATING COST ($/KW-YR) :     .16

        ANNUALIZED   DIRECT OPERATING COST ($/KW-YR) :     .52

        ANNUALIZED COST TO CONTROL ($/KW-YR) :     .69

-------------------------------------------------------------------------
            INITIAL INVESTMENT ($)

        ENGINEERING DESIGN & SUPERVISION                      28586.
        ENGINEERING FEE                                        2287.

        HARDWARE                                              66073.
        INSTALLATION LABOR & SUPERVISION                     118083.
        CONSTRUCTION FACILITIES                                9944.
        SERVICE FACILITIES                                     9208.
        UTILITIES FACILITIES                                   5525.

        CONSTRUCTION FIELD EXPENSE                            27148.
        CONTRACTORS FEE                                       14618.
        CONSTRUCTION CONTINGENCY                              22972.

        INITIAL CHARGES                                          0.
        STARTUP COSTS                                         30444.
      --------------------------------------            ----------
      TOTAL INITIAL INVESTMENT                               334889.
-------------------------------------------------------------------------
            ANNUALIZED OPERATING COST ($/YR)

      INDIRECT OPERATING COSTS

        CAPITAL CHARGES
           DEPRECIATION                                       13396.
           INSURANCE                                           1674.
           REPLACEMENT COSTS                                   1340.
           COST OF CAPITAL & TAXES                            38244.

        CAPITAL CHARGES OF LOST CAPACITY (IF DERATE)
           DEPRECIATION                                          0.
           INSURANCE                                             0.
           REPLACEMENT COSTS                                     0.
           COST OF CAPITAL & TAXES                               0.

        OVERHEAD
           ADMINISTRATIVE OVERHEAD                               0.
           PLANT OVERHEAD                                     33972.

      DIRECT OPERATING COSTS

        FUEL COST PENALTY                                    113022.
        FUEL CREDIT (FOR UNUSED FUEL IF DERATE)       (          0.)
        RAW MATERIALS                                            0.
        CONVERSION COSTS
           ADDITIONAL OPERATING PERSONNEL                        0.
           ADDITIONAL UTILITIES REQUIREMENTS                 160650.
           ADDITIONAL MAINTENANCE                              9208.
           REQUIRED ANALYSES                                     0.
        ANNUAL ROYALTIES                                         0.
        PURCHASED POWER (IF DERATE)                              0.
      --------------------------------------            ----------
      TOTAL ANNUALIZED OPERATING COSTS                       371505.
-------------------------------------------------------------------------
      ANNUALIZED COST TO CONTROL ($/KW-YR)                        .69
```

TABLE 7-21. RETROFIT CONTROL COST: LOW NO_x BURNERS FOR EXISTING OPPOSED WALL COAL-FIRED BOILER (1977 DOLLARS)

```
         MAXIMUM CONTINUOUS RATING (MW) :      540.
         TYPICAL BASELINE NOX EMISSION (PPM AT 3% O2)   :      785.
         TYPICAL CONTROLLED NOX EMISSION (PPM AT 3% O2) :      390.

         DERATE REQUIRED (MW)    : NONE

         FUEL PENALTY (PERCENT) :     .00

         ANNUALIZED LOST CAPACITY CAPITAL CHARGE ($/KW-YR) : NONE

         ANNUALIZED PURCHASED POWER PENALTY ($/KW-YR) : NONE

         INITIAL INVESTMENT ($/KW) :     2.03

         ANNUALIZED INDIRECT OPERATING COST ($/KW-YR) :     .34

         ANNUALIZED   DIRECT OPERATING COST ($/KW-YR) :     .06

         ANNUALIZED COST TO CONTROL ($/KW-YR) :     .40
-----------------------------------------------------------------------------------
                  INITIAL INVESTMENT ($)

         ENGINEERING DESIGN & SUPERVISION                         15592.
         ENGINEERING FEE                                           1247.

         HARDWARE                                                 336000.
         INSTALLATION LABOR & SUPERVISION                         323136.
         CONSTRUCTION FACILITIES                                   35593.
         SERVICE FACILITIES                                        32957.
         UTILITIES FACILITIES                                      19774.

         CONSTRUCTION FIELD EXPENSE                                97170.
         CONTRACTORS FEE                                           52322.
         CONSTRUCTION CONTINGENCY                                  82221.

         INITIAL CHARGES                                               0.
         STARTUP COSTS                                             99601.
      ----------------------------------------             ----------
      TOTAL INITIAL INVESTMENT                                   1095614.
-----------------------------------------------------------------------------------
                  ANNUALIZED OPERATING COST ($/YR)

      INDIRECT OPERATING COSTS

         CAPITAL CHARGES
            DEPRECIATION                                           43825.
            INSURANCE                                               5478.
            REPLACEMENT COSTS                                       4382.
            COST OF CAPITAL & TAXES                               125117.

         CAPITAL CHARGES OF LOST CAPACITY (IF DERATE)
            DEPRECIATION                                               0.
            INSURANCE                                                  0.
            REPLACEMENT COSTS                                          0.
            COST OF CAPITAL & TAXES                                    0.

         OVERHEAD
            ADMINISTRATIVE OVERHEAD                                    0.
            PLANT OVERHEAD                                          6591.

      DIRECT OPERATING COSTS

         FUEL COST PENALTY                                             0.
         FUEL CREDIT (FOR UNUSED FUEL IF DERATE)        (              0.)
         RAW MATERIALS                                                 0.
         CONVERSION COSTS
            ADDITIONAL OPERATING PERSONNEL                             0.
            ADDITIONAL UTILITIES REQUIREMENTS                          0.
            ADDITIONAL MAINTENANCE                                 32957.
            REQUIRED ANALYSES                                          0.
         ANNUAL ROYALTIES                                              0.
         PURCHASED POWER (IF DERATE)                                   0.
      ----------------------------------------             ----------
      TOTAL ANNUALIZED OPERATING COSTS                            218350.
-----------------------------------------------------------------------------------
      ANNUALIZED COST TO CONTROL ($/KW-YR)                           .40
```

TABLE 7-22. RETROFIT CONTROL COST: BURNERS OUT OF SERVICE FOR EXISTING OPPOSED WALL COAL-FIRED BOILER (1977 DOLLARS)[a]

```
            MAXIMUM CONTINUOUS RATING (MW) :     540.
            TYPICAL BASELINE NOX EMISSION (PPM AT 3% O2)   :      785.
            TYPICAL CONTROLLED NOX EMISSION (PPM AT 3% O2) :      510.

            DERATE REQUIRED (MW)   :     108[a]

            FUEL PENALTY (PERCENT) :    .25

            ANNUALIZED LOST CAPACITY CAPITAL CHARGE ($/KW-YR) :    5.33

            ANNUALIZED PURCHASED POWER PENALTY ($/KW-YR) :    45.50

            INITIAL INVESTMENT ($/KW) :    .08

            ANNUALIZED INDIRECT OPERATING COST ($/KW-YR) :    5.34

            ANNUALIZED   DIRECT OPERATING COST ($/KW-YR) :    24.78

            ANNUALIZED COST TO CONTROL ($/KW-YR) :    30.12
-------------------------------------------------------------------------
                 INITIAL INVESTMENT ($)

            ENGINEERING DESIGN & SUPERVISION                       23475.
            ENGINEERING FEE                                         1878.

            HARDWARE                                                   0.
            INSTALLATION LABOR & SUPERVISION                        5049.
            CONSTRUCTION FACILITIES                                  273.
            SERVICE FACILITIES                                       252.
            UTILITIES FACILITIES                                     151.

            CONSTRUCTION FIELD EXPENSE                               744.
            CONTRACTORS FEE                                          401.
            CONSTRUCTION CONTINGENCY                                 630.

            INITIAL CHARGES                                            0.
            STARTUP COSTS                                           3285.
         ----------------------------------------         ----------
         TOTAL INITIAL INVESTMENT                                  36139.
-------------------------------------------------------------------------
                 ANNUALIZED OPERATING COST ($/YR)

         INDIRECT OPERATING COSTS

            CAPITAL CHARGES
               DEPRECIATION                                         1446.
               INSURANCE                                             181.
               REPLACEMENT COSTS                                     145.
               COST OF CAPITAL & TAXES                              4127.

            CAPITAL CHARGES OF LOST CAPACITY (IF DERATE)
               DEPRECIATION                                       558000.
               INSURANCE                                           83700.
               REPLACEMENT COSTS                                   66960.
               COST OF CAPITAL & TAXES                           1593065.

            OVERHEAD
               ADMINISTRATIVE OVERHEAD                                 0.
               PLANT OVERHEAD                                         50.

         DIRECT OPERATING COSTS

            FUEL COST PENALTY                                      90418.
            FUEL CREDIT (FOR UNUSED FUEL IF DERATE)          (  9041760.)
            RAW MATERIALS                                              0.
            CONVERSION COSTS
               ADDITIONAL OPERATING PERSONNEL                          0.
               ADDITIONAL UTILITIES REQUIREMENTS                       0.
               ADDITIONAL MAINTENANCE                                252.
               REQUIRED ANALYSES                                       0.
            ANNUAL ROYALTIES                                           0.
            PURCHASED POWER (IF DERATE)                         19656000.
         ----------------------------------------         ----------
         TOTAL ANNUALIZED OPERATING COSTS                       13012584.
-------------------------------------------------------------------------
         ANNUALIZED COST TO CONTROL ($/KW-YR)                      30.12
```

---

[a] Assumes a 20 percent derate, which is typical when applying BOOS on a coal-fired utility boiler.

TABLE 7-23. RETROFIT CONTROL COST: BURNERS OUT OF SERVICE FOR EXISTING SINGLE WALL OIL- AND GAS- FIRED BOILER (1977 DOLLARS)

```
      MAXIMUM CONTINUOUS RATING (MW) :       90.
      TYPICAL BASELINE NOX EMISSION (PPM AT 3% O2)    :      355 oil/470 gas
      TYPICAL CONTROLLED NOX EMISSION (PPM AT 3% O2) :      210 oil/235 gas

      DERATE REQUIRED (MW)    : NONE

      FUEL PENALTY (PERCENT) :     .25

      ANNUALIZED LOST CAPACITY CAPITAL CHARGE ($/KW-YR) : NONE

      ANNUALIZED PURCHASED POWER PENALTY ($/KW-YR) : NONE

      INITIAL INVESTMENT ($/KW) :     .30

      ANNUALIZED INDIRECT OPERATING COST ($/KW-YR) :     .05

      ANNUALIZED   DIRECT OPERATING COST ($/KW-YR) :     .44

      ANNUALIZED COST TO CONTROL ($/KW-YR) :     .49
--------------------------------------------------------------------------------
              INITIAL INVESTMENT ($)

      ENGINEERING DESIGN & SUPERVISION                          18105.
      ENGINEERING FEE                                            1448.

      HARDWARE                                                      0.
      INSTALLATION LABOR & SUPERVISION                           3366.
      CONSTRUCTION FACILITIES                                     182.
      SERVICE FACILITIES                                          168.
      UTILITIES FACILITIES                                        101.

      CONSTRUCTION FIELD EXPENSE                                  496.
      CONTRACTORS FEE                                             267.
      CONSTRUCTION CONTINGENCY                                    420.

      INITIAL CHARGES                                               0.
      STARTUP COSTS                                              2455.
   ----------------------------------------               ----------
   TOTAL INITIAL INVESTMENT                                     27009.
--------------------------------------------------------------------------------
              ANNUALIZED OPERATING COST ($/YR)

   INDIRECT OPERATING COSTS

      CAPITAL CHARGES
         DEPRECIATION                                            1080.
         INSURANCE                                                135.
         REPLACEMENT COSTS                                        106.
         COST OF CAPITAL & TAXES                                 3084.

      CAPITAL CHARGES OF LOST CAPACITY (IF DERATE)
         DEPRECIATION                                               0.
         INSURANCE                                                  0.
         REPLACEMENT COSTS                                          0.
         COST OF CAPITAL & TAXES                                    0.

      OVERHEAD
         ADMINISTRATIVE OVERHEAD                                    0.
         PLANT OVERHEAD                                            34.

   DIRECT OPERATING COSTS

      FUEL COST PENALTY                                         39123.
      FUEL CREDIT (FOR UNUSED FUEL IF DERATE)       (               0.)
      RAW MATERIALS                                                 0.
      CONVERSION COSTS
         ADDITIONAL OPERATING PERSONNEL                             0.
         ADDITIONAL UTILITIES REQUIREMENTS                          0.
         ADDITIONAL MAINTENANCE                                   168.
         REQUIRED ANALYSES                                          0.
      ANNUAL ROYALTIES                                              0.
      PURCHASED POWER (IF DERATE)                                   0.
   ----------------------------------------               ----------
   TOTAL ANNUALIZED OPERATING COSTS                             43733.
--------------------------------------------------------------------------------
   ANNUALIZED COST TO CONTROL ($/KW-YR)                           .49
```

TABLE 7-24. RETROFIT CONTROL COST: FLUE GAS RECIRCULATION AND OVERFIRE AIR FOR EXISTING SINGLE WALL OIL- AND GAS-FIRED BOILER (1977 DOLLARS)

```
      MAXIMUM CONTINUOUS RATING (MW) :       90.
      TYPICAL BASELINE NOX EMISSION (PPM AT 3% O2)   :      355 oil/470 gas
      TYPICAL CONTROLLED NOX EMISSION (PPM AT 3% O2) :      155 oil/115 gas

      DERATE REQUIRED (MW)    : NONE

      FUEL PENALTY (PERCENT) :    .50

      ANNUALIZED LOST CAPACITY CAPITAL CHARGE ($/KW-YR) : NONE

      ANNUALIZED PURCHASED POWER PENALTY ($/KW-YR) : NONE

      INITIAL INVESTMENT ($/KW) :     5.71

      ANNUALIZED INDIRECT OPERATING COST ($/KW-YR) :     1.14

      ANNUALIZED   DIRECT OPERATING COST ($/KW-YR) :     1.91

      ANNUALIZED COST TO CONTROL ($/KW-YR) :     3.05
----------------------------------------------------------------------
             INITIAL INVESTMENT ($)

      ENGINEERING DESIGN & SUPERVISION                      30838.
      ENGINEERING FEE                                        2467.

      HARDWARE                                             194850.
      INSTALLATION LABOR & SUPERVISION                      97025.
      CONSTRUCTION FACILITIES                               15761.
      SERVICE FACILITIES                                    14594.
      UTILITIES FACILITIES                                   8756.

      CONSTRUCTION FIELD EXPENSE                            43028.
      CONTRACTORS FEE                                       23169.
      CONSTRUCTION CONTINGENCY                              36408.

      INITIAL CHARGES                                           0.
      STARTUP COSTS                                         46690.
    ------------------------------------                ----------
    TOTAL INITIAL INVESTMENT                               513587.
----------------------------------------------------------------------
             ANNUALIZED OPERATING COST ($/YR)

    INDIRECT OPERATING COSTS

      CAPITAL CHARGES
         DEPRECIATION                                       20543.
         INSURANCE                                           2568.
         REPLACEMENT COSTS                                   2054.
         COST OF CAPITAL & TAXES                            58651.

      CAPITAL CHARGES OF LOST CAPACITY (IF DERATE)
         DEPRECIATION                                           0.
         INSURANCE                                              0.
         REPLACEMENT COSTS                                      0.
         COST OF CAPITAL & TAXES                                0.

      OVERHEAD
         ADMINISTRATIVE OVERHEAD                                0.
         PLANT OVERHEAD                                     18669.

    DIRECT OPERATING COSTS

      FUEL COST PENALTY                                     78246.
      FUEL CREDIT (FOR UNUSED FUEL IF DERATE)       (          0.)
      RAW MATERIALS                                             0.
      CONVERSION COSTS
         ADDITIONAL OPERATING PERSONNEL                         0.
         ADDITIONAL UTILITIES REQUIREMENTS                  78750.
         ADDITIONAL MAINTENANCE                             14594.
         REQUIRED ANALYSES                                      0.
      ANNUAL ROYALTIES                                          0.
      PURCHASED POWER (IF DERATE)                               0.
    ------------------------------------                ----------
    TOTAL ANNUALIZED OPERATING COSTS                       274075.
----------------------------------------------------------------------
    ANNUALIZED COST TO CONTROL ($/KW-YR)                     3.05
```

All cost input data and assumptions are listed in Appendix E. For control cost projection purposes, the results shown should be considered valid to only two significant figures. Obviously, the cost code input figures of Appendix E and the intermediate results in Tables 7-19 through 7-24 were not rounded off in the computer code to minimize errors in the calculations. It will be noted that the final figure, \$/kW-yr, for each control case has been rounded to the two significant figure accuracy.

It should be reiterated that the results presented are only representative typical retrofit control costs. They represent retrofitting relatively new boilers, say 5 to 10 years old, with at least 25 years of service remaining. In any event, these relatively new boilers would likely be the first to be controlled under any proposed retrofit emissions regulations for existing boilers.

Although the control hardware, engineering and installation costs for the retrofit cases considered are well documented, the initial investments could, in selected cases, be doubled if accessibility problems and startup difficulties are severe. Another key point of the analysis is that any loss in boiler efficiency due to a NO_x control, cited in the tables as a fuel penalty, would result in a severe cost penalty. For example, in the case of OFA for the typical 540 MW opposed wall unit treated in Table 7-20, a 0.25 percent lost in unit efficiency resulted in an annual cost of \$113,000 or \$0.21/kW-yr based on a 7000 hour operating year. This is almost a third of the total control cost. Thus, there is a definite need for careful, long-term monitoring of control behavior to unequivocally determine any losses in boiler efficiency or additional maintenance requirements.

The results in Tables 7-19 through 7-24 represent the best projections to date based on discussions with equipment manufacturers and vendors, retrofit design studies, and detailed process analyses. They are in basic agreement with the work of Selker and Krippene discussed in Section 7.1 if adjustments to constant year/dollars are made. The operating costs presented here for tangential coal-fired NO_x control are somewhat higher than Selker's estimates, and are thus conservative. However, the main thrust in this analysis was to compare control costs for a variety of applications, all on an equal and well documented basis.

Based on the favorable process analysis results presented in Section 6, it is evident from an examination of Tables 7-25 and 7-26 that OFA and LNB are the preferred, cost-effective NO_x controls for coal firing. For very high level of NO_x control of coal-fired units (170 ng/J), both OFA and LNB would be required. For more moderate levels of control, LNB would seem to be less expensive and more cost-effective than OFA in reducing NO_x.

Table 7-26 also presents projected retrofit control requirements for alternative NO_x emissions levels. Control requirements are recommended to achieve a given NO_x emission level. These requirements and techniques combined with the cost to control column, complete the cost effectiveness picture. Since this study has been completed (1978), manufacturers have acquired more long term experience with low NO_x burners, and are now recommending LNB over OFA even for retrofit applications (Reference 7-24). In any event, the choice of retrofitting LNB or OFA must be decided on a case-by-case basis, based on fuel/furnace design considerations. For example, although LNB may appear to be preferable operational-wise, as well as cost-wise, the existing furnace may not be of the proper design or size to accommodate the larger, less turbulent flame. In that case, OFA may be more suitable. Another example would be a furnace firing a high slagging potential coal; OFA would not be attractive because it could increase that slagging potential.

Burners out of service was treated in the cost analysis not as a recommended control technique for coal firing but to show the prohibitively high cost of derating. As detailed in Table 7-22, this high cost was due principally to the need to purchase make up power from elsewhere and to account for the lost capacity of the system through a lost capacity capital charge.

As far as moderate control for oil- and gas-fired units, off stoichiometric combustion via BOOS appears to be the preferred route, as indicated in Tables 7-25 and 7-26. Initial investment is minimized since there are no associated major hardware requirements, only engineering and startup costs. To reach the next level of NO_x control, 86 ng/J, FGR and OFA installation would seem to be in order. However, the increase in cost from $0.49/kW-yr for BOOS to $3/kW-yr for FGR + OFA does not make the option attractive. Besides, from a regulatory point of view, requirement of

TABLE 7-25. SUMMARY OF RETROFIT CONTROL COSTS[a] (1977 DOLLARS)

Boiler/Fuel Type	Initial Investment ($/kW)	Annualized Indirect Operating Cost ($/kW-yr)	Annualized Direct Operating Cost ($/kW-yr)[b]	Total to Cost Control ($/kW-yr)[b]
Tangential/Coal-Fired				
OFA	0.90	0.21	0.32	0.53
Opposed Wall/Coal-Fired				
OFA	0.62	0.16	0.52	0.69
LNB	2.03	0.34	0.06	0.40
BOOS	0.08	5.34	24.78	30.12
Single Wall/Oil- and Gas-Fired				
BOOS	0.30	0.05	0.44	0.49
FGR/OFA	5.71	1.14	1.91	3.05

[a] Based on assumptions given in text and costs input parameters listed in Appendix E.

[b] Based on 7000 h operating year. Typical costs only.

[c] Assumes twenty percent derate required.

TABLE 7-26. PROJECTED RETROFIT CONTROL REQUIREMENTS FOR ALTERNATE NO_x EMISSIONS LEVELS

Fuel/NO_x Emission Level ng/J (lb/10 Btu)	Recommended Control Requirement[a]	Cost to Control $/kW-yr[b,c]
Coal		
301 (0.7)	OFA[d]	0.50 to 0.70
258 (0.6)	OFA[d]	0.50 to 0.70
215 (0.5)	LNB	0.40 to 0.50
172 (0.4)	OFA + LNB	0.95 to 1.20
Oil		
129 (0.3)	BOOS	0.50 to 0.60
86 (0.2)	FGR + OFA	~3.00
Gas		
129 (0.3)	BOOS	0.50 to 0.60
86 (0.2)	FGR + OFA	~3.00
43 (0.1)	FGR + OFA	~3.00

[a] LEA considered standard operating practice.

[b] Typical installation only; could be significantly higher.

[c] 1977 dollars.

[d] As manufacturers acquire more experience with LNB, they are now recommending LNB over OFA.

the emission level achievable with FGR + OFA would not be particularly attractive since oil- and gas-fired units with BOOS would already have very low NO_x emissions, 129 ng/J, compared to coal-fired units. Furthermore, with impending fuel shortages, oil- and gas-fired units will be eventually phased out.

7.4 CONTROL COSTS FOR NSPS BOILERS

Estimating the incremental costs of NO_x controls for NSPS boilers is in some respects an even more difficult task than costing retrofits. Certain modifications on new units, though effective in reducing NO_x emissions, were originally incorporated due to operational considerations rather than from a control viewpoint. For example, the furnace of a typical unit designed to meet 1971 NSPS (301 ng/J, 0.7 lb/10^6 Btu) has been enlarged to reduce slagging potential. But this also reduces NO_x due to the lowered heat release rate, as established in Section 4. Thus, since the design change would have been implemented even without the anticipated NO_x reduction, the cost of that design modification should not be attributed to NO_x control.

Babcock & Wilcox has estimated the incremental costs of NO_x controls on an NSPS coal-fired boiler (Appendix A). The two units used in the comparison were identical except for NO_x controls on the NSPS unit which included:

- Replacing the high turbulence, rapid mixing cell burner with the limited turbulence dual register (low NO_x) burner
- Increasing the burner zone by spreading the burners vertically to include 22 percent more furnace surface
- Metering and controlling the airflow to each row of burners using a compartmented windbox

To provide these changes for NO_x control, the price increase was about \$1.75 to \$2.50/kW (1977 dollars). If these costs are annualized according to the format of Section 7.2, they translate to 0.28 to 0.40 \$/kW-yr.

Comparing these costs with the retrofit costs (0.40 to 0.70 \$/kW-yr for LNB or OFA) presented in Section 7.3 and considering the better NO_x control anticipated with NSPS units, it is certainly more cost-effective to implement controls on new units. Furthermore, fewer operational problems are expected with factory installed controls.

Foster Wheeler has provided the NO_x Environmental Assessment Program with a detailed design study aimed at identifying the incremental costs of NO_x control inclusive in NSPS units (Appendix B). Foster Wheeler looked at these unit designs with the following results:

	Boiler Design	Relative Cost
Unit 1:	Pre-NSPS base design	100
Unit 2:	Enlarged Furnace, no active NO_x control	114
Unit 3:	NSPS design; enlarged furnace, low NO_x burner, perforated hood, overfire air, boundary air	115.5

Assuming the cost of a pre-NSPS coal fired boiler to be about \$100/kW in 1969, or \$180/kW in 1977 construction costs (References 7-25 through 7-27), the incremental cost of active NO_x controls (LNB plus OFA) is \$2.70/kW, or about \$0.43/kW-yr annualized. The Foster Wheeler estimate which includes both LNB and OFA, thus agrees quite well with the Babcock & Wilcox estimate, which includes only LNB and associated equipment.

Recent emissions test data from the above manufacturers indicate that control levels of 172 to 215 ng/J (0.4 to 0.5 $lb/10^6$ Btu) for coal-firing may be possible with the combination of overfire air and low NO_x burners (References 7-28 and 7-29). However, the viability of long term controlled operation for a variety of coals remains to be demonstrated.

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SECTION 8
ENVIRONMENTAL ASSESSMENT

The evaluation of the effectiveness and impacts of NO_x combustion controls applied to utility boilers must also include an analysis of the effect of these controls on incremental emissions of other pollutants as well as NO_x. Section 8.1 summarizes the demonstrated or predicted effects of controls on waste stream pollutant concentrations, including the latest results from a coal-fired utility boiler field tested under this NO_x EA program. As a step toward quantifying how low NO_x firing affects the environmental impact of a combustion source, a Source Analysis Model, SAM IA (References 8-1 and 8-2), was applied to the results of that utility boiler field test.

To complete the environmental assessment picture, Sections 8.2 through 8.5 summarize the highlights presented earlier in this report of process impacts including energy impacts, economic impact, and control effectiveness of combustion modifications, respectively. With these analyses in hand, Section 8.6 concludes with control technology and R&D recommendations.

8.1 ENVIRONMENTAL IMPACT

Modification of the combustion process in utility boilers for NO_x control in turn reduces the ambient levels of NO_2, which is both a toxic substance and a potential precursor for nitrate aerosols, nitrosamines, and other elements of photochemical smog. These modifications can also cause changes in emissions of other combustion generated pollutants. If unchecked, these changes, referred to here as incremental emissions, may have an adverse effect on the environment, in addition to effects on overall system performance. However, since the incremental emissions are sensitive to the same combustion conditions as NO_x, they may, with proper engineering, also be held to acceptable levels during control development so that the net environmental benefit is maximized. In fact, control of incremental emissions of carbon monoxide, hydrocarbons, and particulate has been a key part of all past NO_x control development programs. In addition, recent control development has been giving increased attention to other potential pollutants such as sulfates, organics, and trace metals.

This section presents data obtained to date on the demonstrated or predicted effects of combustion modification NO_x controls on incremental emissions from utility boilers. Attention is focused on the flue gas emissions, as the limited data base is concentrated in this area. Besides, flue gas stream environmental impacts are expected to dominate over those of liquid and solid effluent streams, as will be discussed later in this section. Emission categories discussed in detail are incremental carbon monoxide, vapor phase hydrocarbons, particulates, trace metals, sulfates, and condensed phase organic compounds. Where appropriate, the results from low NO_x testing of a 180 MW tangential coal-fired utility boiler will be highlighted, as that test program emphasized the impact of controls on incremental emissions and represents the latest reported field results. Details of the boiler tested, the test program performed, and test results obtained are presented in a separate report (Reference 8-1).

8.1.1 Carbon Monoxide Emissions

Since large quantities of CO in the flue gas of utility boilers mean decreased efficiency, utility boilers are operated to keep CO emissions at a minimum. Furthermore, if flue gas CO levels reach concentrations in excess of 2000 ppm, the potential exists for severe equipment damage from potential explosions in flue gas exit passages. Thus, the degree to which a NO_x reduction technique is allowed to increase CO is limited by other than environmental concerns. In general, a NO_x control method can be applied until flue gas CO reaches about 200 ppm. Further application is then curtailed.

NO_x control effects on CO emissions are highly dependent on the equipment type and the fuel fired. In utility boilers of newer design, it is generally possible to achieve good NO_x reduction without causing significant CO production. This is possible because newer burner and furnace designs allow for better combustion air control and longer combustion gas residence time. In addition, oil- and coal-fired boilers usually emit very low CO levels during low NO_x combustion because smoke and soot production generally occurs with these fuels before significant CO levels are attained. Since boiler operators strive to keep combustible losses to a minimum, conditions which result in soot formation are avoided, resulting in correspondingly low CO levels. A summary of the field data on the effects on CO emissions of the more extensively implemented combustion modifications are shown in Table 8-1. These data are discussed below for each combustion NO_x control.

As the data in Table 8-1 illustrate, lower excess air levels in utility boilers can have profound effects on CO emissions. In virtually all instances CO emissions increased significantly when excess O_2 levels were reduced 30 to 60 percent. Gas-fired boilers showed emission increases up to 400 percent when excess O_2 was lowered over this range, while oil-fired boilers were less sensitive, and showed CO emission increases from 0 to 120 percent. However coal-fired boilers were the most sensitive to excess air reductions. Reducing excess O_2 by 40 to 60 percent gave 100 to 1,000 percent increases in CO emissions.

Off stoichiometric combustion has proven to be a very effective NO_x reduction technique for large steam generators. As noted in Section 3, it can be implemented in a variety of ways including burners out of service, overfire air ports, and biased firing. In all cases, the effectiveness of off stoichiometric combustion in reducing NO_x emissions depends in large part on the fraction of total combustion air that can be introduced into the second combustion stage. It is in this second stage that complete combustion of the fuel is achieved. CO emissions rise when this second stage combustion does not go to completion prior to quenching in the convective section. This is caused by a combination of the first stage being too fuel rich and the mixing of second stage air being too slow for the residence time provided. During development of retrofit or new design controls, these parameters are usually selected so that CO emissions are acceptable.

The effectiveness of off stoichiometric combustion in reducing NO_x formation while keeping CO emissions low is highly dependent on specific equipment type. New utility boilers with multiburner furnaces are especially amenable to this technique because it is generally not

TABLE 8-1. REPRESENTATIVE EFFECTS OF NO_x CONTROLS ON CO EMISSIONS FROM UTILITY BOILERS (References 8-3 through 8-7)

NO_x Control	Fuel	CO Emissions (ppm)[a]	
		Baseline	NO_x Control
Low Excess Air	Natural Gas	14	68
		86	74
		12	61
		8	8
		14	34
	Oil	19	42
		85	53
		15	20
		19	19
	Coal	42	93
		20	60
		24	283
		27	81
		27	225
Off Stoichiometric Combustion	Natural Gas	14	16
		86	67
		12	13
		14	14
	Oil	19	21
		85	85
		15	21
		28	37
	Coal	24	23
		27	26
		17	40
		31	45
		29	35
		29	22
Flue Gas Recirculation	Natural Gas	175	65
	Oil	21	9
Load Reduction	Natural Gas	14	13
		52	52
		12	15
		14	21
	Oil	19	14
		30	5
		15	19
		19	22
	Coal	20	41
		25	19
		31	8
		24	12

[a] 3% O_2, dry basis.

difficult to adequately distribute secondary air and assure complete combustion in these sources. Consequently, implementing off stoichiometric combustion in utility boilers is expected to elicit little effect on incremental CO emissions. This conclusion is certainly borne out by the representative data presented in Table 8-1.

The use of flue gas recirculation (FGR) for NO_x control has, in practice, been restricted to gas- and oil-fired units. This technique is ineffective in reducing fuel NO_x production, the predominant source of NO_x in coal firing (Reference 8-8). When FGR is implemented, 10 to 30 percent of the total burner gas flow is recycled flue gas from the boiler exhaust. Further FGR increases can cause flame instability due to reduced flame temperatures and oxygen availability. Theoretically, FGR can lead to increased CO emissions, but unacceptable flame instabilities usually occur before the onset of CO or smoke production. Thus, as Table 8-1 shows, the use of FGR has not caused increased CO emissions. On the contrary, CO emissions have decreased in the cases shown.

Since load reduction in steam generators necessitates increased excess air levels to maintain good furnace air-fuel mixing and steam temperature control, increased CO emissions using this NO_x reduction technique are not expected. In addition, the increased combustion gas residence time afforded under reduced load would tend to facilitate complete CO burnout. As Table 8-1 illustrates, CO emissions remain relatively unchanged with reduced load.

8.1.2 Hydrocarbon Emissions

Field test programs studying the effectiveness of NO_x controls often monitor flue gas HC emissions as a supplementary measure of boiler efficiency. Therefore, some data on the effect of these controls on HC emissions are available. Three recent test programs on utility boilers routinely measured flue gas HC (References 8-3 through 8-5). However, in virtually all tests, both baseline and low NO_x operation, hydrocarbon emissions were less than 1 ppm (or below the detection limit of the available monitoring instrument). Thus, it was concluded that HC emissions are relatively unaffected by imposing preferred NO_x combustion controls on large utility boilers. However, this conclusion is not altogether unexpected. The presence of unburned HC in flue gases implies poor boiler operating efficiency, and NO_x controls which significantly decrease efficiency have found little acceptance.

8.1.3 Particulate Emissions

Although gas-fired units produce negligible amounts of particulate, oil- and coal-fired utility boilers currently emit approximately 38 percent of the nationwide particulate and smoke emissions (Reference 8-7). Potential adverse effects on these particulate emissions from NO_x combustion controls could therefore have significant environmental impact. Unfortunately the optimum conditions for reducing particulate formation (intense, high temperature flames as produced by high turbulence and rapid fuel-air mixing), are not the conditions for suppressing NO_x formation. Therefore, most attempts to produce low NO_x combustion designs have been compromised by the need to limit formation of particulates. This compromise has generally produced designs which maintain a well controlled, cool flame, while still providing sufficient gas residence time to completely burn carbon containing particles.

The NO_x combustion controls currently receiving the most widespread application in utility boilers are low excess air, off stoichiometric combustion, and flue gas recirculation (for gas and oil). The altered combustion conditions resulting from these modifications can be expected to influence emitted particulate load and size distribution. For example, smoke and particulate emissions tend to increase as available oxygen is reduced (soot emissions increase and ash particles contain more carbon). Thus the degree to which excess air can be lowered to control NO_x is usually limited by the appearance of smoke, especially in oil-fired units. Of course, the extent to which excess air can be limited depends on equipment types and design. Many modern burners can operate on as little as 3 to 5 percent excess air.

Similarly, the degree to which off stoichiometric combustion can be employed is frequently limited by the degree to which the primary flame zone can be stably operated fuel-rich, how well the second stage air mixes with primary stage combustion products, and the residence time for combustion in the second stage. Soot and carbon particles formed in the fuel-rich primary stage tend to resist complete combustion downstream of the primary stage.

On the other hand, flue gas recirculation on oil-fired units can serve to decrease particulate emissions by providing more intimate mixing. Kamo, et al. (Reference 8-9) have demonstrated that recirculation rates of 40 to 50 percent on a heater-sized oil-fired furnace reduced the smoke number significantly.

Published data on the effects of NO_x reduction techniques on particulate emissions from utility boilers are scattered and insufficient for indepth analysis. Table 8-2 summarizes the particulate emissions data obtained during four recent field test programs which studied coal-fired utility boilers (References 8-3, 8-4, 8-5, and 8-10). During the studies, particulate measurements were recorded under baseline and low NO_x conditions. Since these NO_x conditions were generally produced by a combination of low excess air and off stoichiometric combustion, the individual effect of each technique on particulate emissions cannot be determined. Nevertheless, the data do show that particulate emissions are relatively unaffected by low NO_x firing.

The effects of low NO_x firing on carbon (or combustible) content of the particulate are also shown in Table 8-2. Although the data are quite scattered, it appears that carbon losses increase for single wall- and opposed wall-firing under low NO_x conditions, but decrease slightly for tangential firing. However, the changes are small and may not be significant.

The effect of low NO_x conditions on emitted particle size distribution have also been investigated to a limited extent (References 8-3, 8-4, and 8-10). The data from a study of particle size distribution in six boilers are summarized in Table 8-3. As the table shows, no significant changes were noted in five of the boilers. For the opposed wall coal-fired boiler, a distinct shift to smaller particles was noted, but the author reported problems with the sampling and particle sizing equipment in this test, so the data may not be significant (Reference 8-4).

8.1.4 Trace Metals

Emissions of trace metals are a concern for combustion sources firing coal and residual oil. They are a lesser problem in sources firing distillate fuels since trace metal concentrations in distillate oils are generally much lower than those in residual oils. Trace metals from

TABLE 8-2. EFFECTS OF NO_x CONTROLS ON PARTICULATE EMISSIONS FROM COAL-FIRED UTILITY BOILERS (References 8-3, 8-4, 8-5 and 8-10)

Firing Mode	Particulate Emissions (μg/J)		Percent Carbon in Particulate		References
	Baseline	Low NO_x	Baseline	Low NO_x	
Single Wall	2.3 1.9 2.0-3.4	1.8-2.0 2.3 1.7-2.4	9.1-13.0 5.1 5.9-6.3	6.2-8.1 8.2 8.5-12.4	8-4 8-5 8-5
Single Wall (wet bottom)	0.7-1.3	0.6-1.8	1.3-2.2	1.7-5.8	8-10
Opposed Wall	1.6-2.1 3.3-3.8 1.3-1.7	1.9-2.6 2.4-3.6 1.3-1.8	1.1-2.7 0.5-0.7 2.8-5.5	3.4-5.7 0.2-0.5 6.7-11.8	8-4 8-5 8-5
Tangential	1.1-1.8 1.3-1.4 0.9-2.2 1.4	1.2-3.0 1.0-1.3 2.4-2.4 1.2-1.4	0.9-2.0 0.6-0.7 24.2-25.8 2.7	0.8-1.5 0.2-0.6 14.8-18.8 2.3-2.8	8-4 8-4 8-5 8-3

TABLE 8-3. EFFECT OF NO_x CONTROLS ON EMITTED PARTICLE SIZE DISTRIBUTION FROM UTILITY BOILERS

Equipment Type: Fuel	Firing Condition	Average Weight Percent Particles of Size:						References
		>2.5 µm	2.0 µm	1.5 µm	1.0 µm	0.5 µm	<0.5 µm	
Tangential Coal	Baseline	81.78	9.12	2.01	2.64	2.92	1.55	8-4
	Low NO_x	80.74	8.91	2.28	2.92	3.25	1.88	
Tangential Coal	Baseline	92.75	2.97	0.70	0.97	1.21	1.38	8-4
	Low NO_x	93.94	1.89	0.59	0.86	1.10	1.61	
Opposed Wall Coal	Baseline	92.56	2.59	0.62	0.96	1.45	1.84	8-4
	Low NO_x	59.37	10.77	4.08	5.89	9.55	10.36	
Single Wall Coal (wet bottom)	Baseline	85.0	3.5	2.27	2.23	1.17	5.83	8-10
	Low NO_x	86.43	5.27	1.8	1.97	1.27	3.27	
Opposed Wall Oil	Baseline	84.6	0.9	1.7	1.3	1.3	8.2	8-10
	Low NO_x	80.0	2.0	2.0	2.5	2.7	10.8	

		>10 µm	3-10 µm	1-3 µm	<1 µm			
Tangential Coal	Baseline	36.8	40.3	18.1	4.8			8-3
	Low NO_x	35.4	42.1	17.6	4.9			

stationary sources are emitted to the atmosphere with the flue gas either as a vapor or condensed on particulate. The quantity of any given metal emitted, in general, depends on:

- Its concentration in the fuel
- The combustion conditions in the boiler
- The type of particulate control device used, and its collection efficiency as a function of particle size
- The physical and chemical properties of the element itself

For present purposes, the trace metal composition of the fuel is considered a given quantity not subject to manipulation. Therefore although composition has a controlling effect on the absolute trace metal emissions from a combustion source, it is not considered as a factor to explain the effects NO_x controls have on incremental trace metal emissions.

It has become widely recognized that some trace metals tend to concentrate in certain waste particle streams from a boiler (bottom ash, collector ash, flue gas particulate), while others do not (References 8-11 through 8-18). Based on this phenomenon, three classes of partitioning metals have been defined (References 8-11 and 8-12).

- Class I: 20 metals (Al, Ba, Ca, Ce, Co, Eu, Fe, Hf, K, La, Mg, Mn, Rb, Sc, Si, Sm, Sr. Ta, Th, and Ti). These are found in the bottom ash or slag, the particle collector inlet flyash, and the collector outlet flyash in approximately the same mass concentrations.
- Class II: 9 metals (As, Cd, Cu, Ga, Pb, Sb, Se, Sn, and Zn). These are not usually found in bottom ash or slag, but are found in flyash. Mass concentrations in particle collector inlet flyash are generally less than in collector outlet flyash.
- Class III: Hg, and possibly Se. These are usually emitted as vapors in the flue gas.

Another set of elements (Cr, Cs, Na, Ni, U, and V) exhibits properties intermediate between Classes I and II.

Other work has shown that the Class II metals, As, Cd, Pb, Sb, Se, and Zn, along with Ni, Cr, and V become increasingly more concentrated in flyash particles as particle size decreases (Reference 8-13). Cd, Pb, Ni, Sb, Se, Sn, V and Zn all appear to have a mass mean diameter (MMD) of less than 1 μm in the atmosphere. The more common Class I metals, Fe, Al, and Si, have MMDs of 2.5 to 7.0 μm (Reference 8-19).

The most logical explanation for this segregation behavior involves a volatilization-condensation mechanism (Reference 8-11). In its simplest form, the argument says that Class I metals have boiling points sufficiently high that they are not volatilized in the combustion zone. Instead, they form a melt of relatively uniform concentration, which becomes both bottom ash or slag, and flyash. Thus, Class I elements remain in a condensed phase throughout the boiler and show little partitioning with particle size. By contrast, Class II metals have boiling points below peak combustion temperatures, so they are volatilized in the combustion zone and do not become incorporated in the slag. As combustion gases cool by traveling through the boiler, these elements either form condensation nuclei or condense onto other available solid surfaces (predominantly Class I mineral particles). Since the available surface area to mass ratio increases as particle size decreases, Class II elements concentrate in small particles. This partitioning mechanism is further substantiated by observations that certain Class II metals exhibit higher surface concentrations than bulk concentrations in fine particles (Reference 8-20).

This simple mechanism described above does not fully account for all experimental observations. For example, Ca and Cu behave as high boiling point metals, whereas Rb, Cs, and Mg behave as volatile elements. Therefore, the volatilization-condensation mechanism has been extended as follows (Reference 8-11):

- Trace elements in coal are present as aluminosilicates, sulfides, and organometallics
- On combustion, the aluminosilicates melt to form slag or bottom ash, and flyash
- In the reducing atmosphere during initial stages of combustion, metal sulfides are reduced to vapor phase metal; at the same time the organic matrix of organometallics oxidizes, leaving volatilized metal
- Volatilized metals may themselves become oxidized to less volatile oxides
- As the combustion gas cools, these volatile species condense onto available solid surfaces, and concentrate in small particles

- Since slag and flue gas are in contact for only a short time, little volatile condensation in slag occurs

This extended mechanism is indirectly supported by the fact that Class I metals are largely geochemical lithophiles (readily associated with aluminosilicate minerals), while Class II metals are largely chalcophiles (readily incorporated into sulfide minerals).

In all mechanisms the Class III metals, Hg and to some extent Se, remain vaporized through the stack and are emitted as flue gas vapor components. Some 90 percent of Hg emissions (Reference 8-21) and about 20 percent of Se emissions (Reference 8-11) are emitted as vapors.

Regardless of the exact mechanism for the trace metal partitioning phenomenon, the partitioning significantly influences trace metal emissions from combustion sources with particulate control devices. All particle collection devices are more efficient at collecting large particles than small particles. Since Class II metals in flyash occur in smaller particles than Class I metals, a larger fraction of the Class II elements introduced into a boiler will be emitted from sources equipped with particulate control units.

This behavior is illustrated by recent trace metal emissions data from industrial boilers (Reference 8-22). Figure 8-1 shows the concentration of several Class I metals measured in particle samples from different points in a coal-fired industrial boiler. Figure 8-2 shows the same profile for several Class II elements. As the partitioning theory predicts, the concentration of Class I metals remains fairly constant throughout the boiler. On the other hand, flyash concentrations of Class II elements increase toward the flue gas exit. The expected increase in concentrations in the collector effluent ash over collector inlet ash and collected ash is quite significant.

By understanding trace metal partitioning and concentration in fine particulate, it is possible to postulate the effects NO_x combustion controls will have on incremental trace metal emissions. Several NO_x controls for boilers result in lowered peak flame temperatures (off stoichiometric combustion, flue gas recirculation, reduced air preheat, load reduction, and water injection). The volatilization-condensation theory predicts that if the combustion temperature is reduced, less

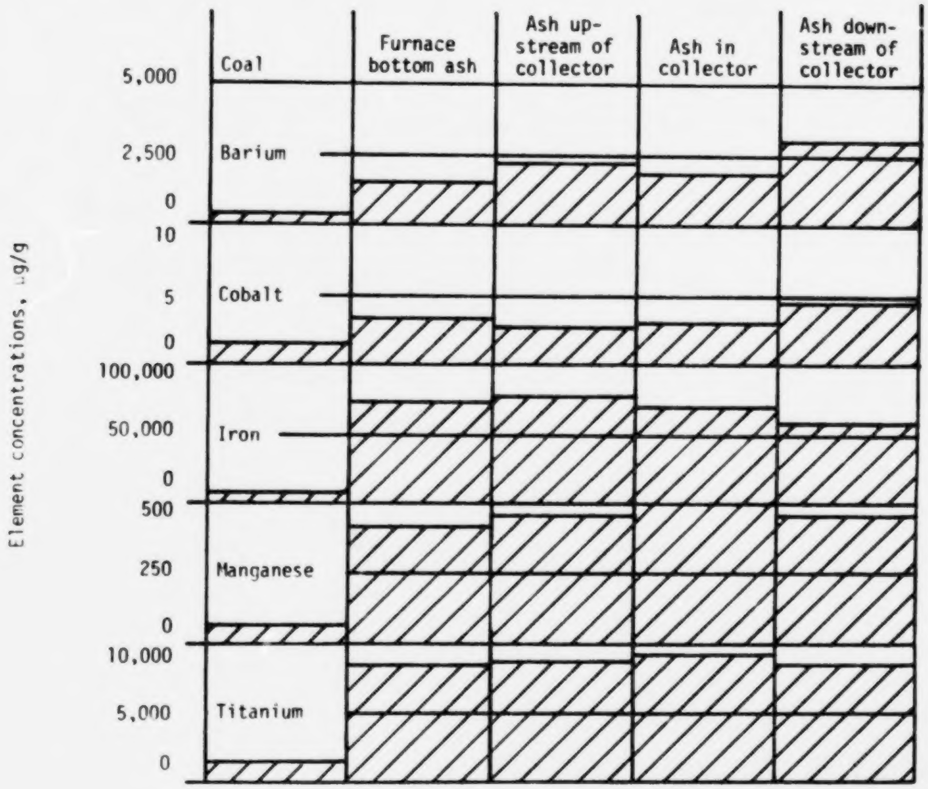

Figure 8-1. Partitioning of Class I elements (Reference 8-22).

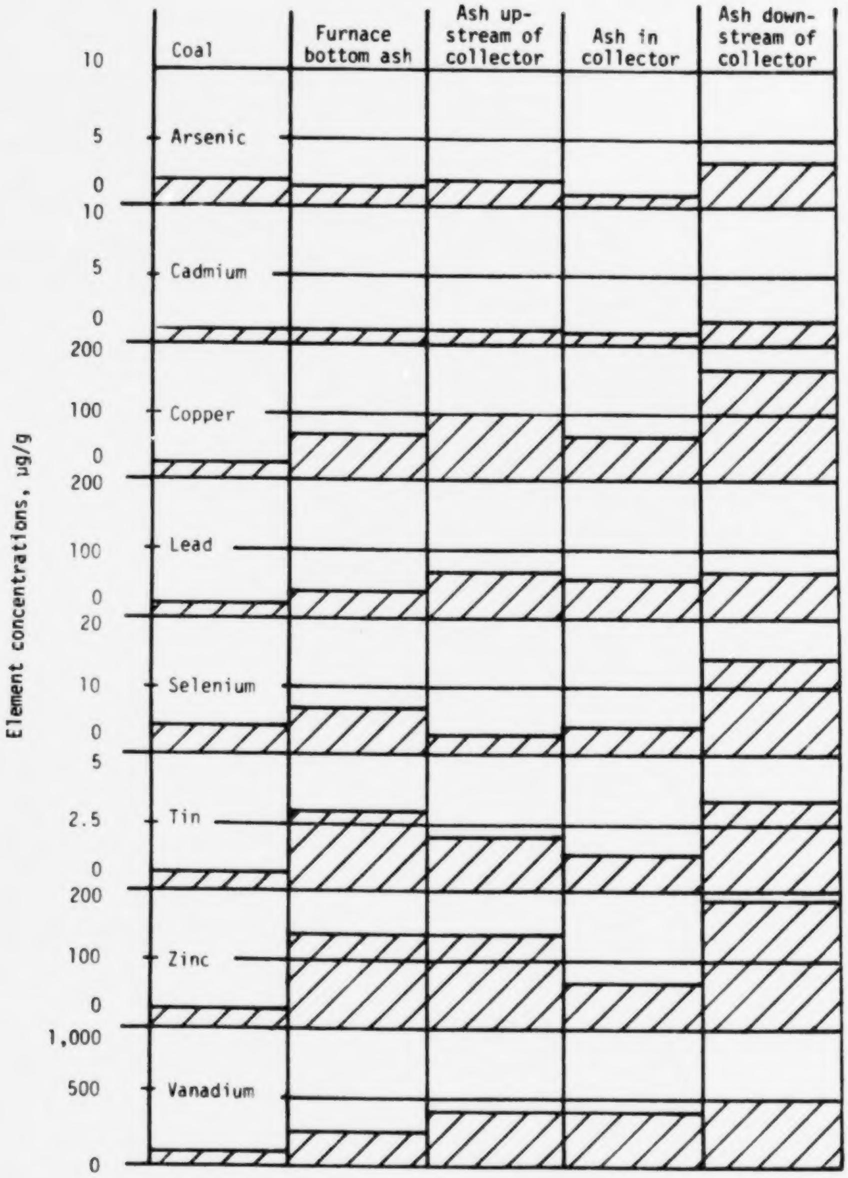

Figure 8-2. Partitioning of Class II elements (Reference 8-22).

Class II metal will initially volatilize, hence less will be available for subsequent condensation. Under these conditions (lowered flame temperature), it is expected that less Class II metal (the segregating trace metals) will be redistributed to small particulate. Therefore, in boilers with particulate controls, lowered volatile metal emissions should result. Class I metal (the nonsegregating trace metals) emissions should remain relatively unchanged. Since 8 of the 20 most toxic elements in air are Class II metals, obtaining trace metal partitioning data should be given high priority (Reference 8-23).

Lowered local O_2 concentrations are also expected to affect segregating metal emissions from boilers with particle controls. Lowered O_2 availability decreases the possibility of volatile metal oxidation to less volatile oxides. Under these conditions Class II metals should remain in the vapor phase into the cooler sections of the boiler. More redistribution to small particles should occur and emissions should increase. Again, nonsegregating metal emissions should be unaffected. This behavior is expected when low excess air is implemented. Other combustion NO_x controls which decrease local O_2 concentrations (off stoichiometric combustion and flue gas recirculation) also reduce peak flame temperature. For these, the effect of lowered combustion temperature might be expected to predominate.

The effect of NO_x combustion controls on segregating metal emissions from combustion sources without particle collection devices should be marginal at best. Particle redistribution will not affect mass emissions because all particulate produced is emitted from these sources. However, since trace metal condensation on internal boiler surfaces may occur, conditions which decrease the extent of Class II metal volatilization (lowered peak flame temperature) might cause a slight decrease in segregating metal emissions. Conversely, conditions which increase metal volatility (low local O_2 concentrations) may cause slight increases in volatile metal emissions.

Trace metal sampling was performed at a coal-fired utility boiler under baseline and low NO_x conditions (burners out of service or biased burner firing) as part of the NO_x EA Program (Reference 8-3). Trace element concentrations in the bottom ash were compared to those in the flyash (boiler outlet) to determine if trace element stream partitioning could be observed. The trace elements were placed into three groupings depending on whether; (EQ) the metal was partitioned about equally between bottom ash and flyash (less than a factor of two difference, behavior expected of Class I elements); (FA) the material was preferentially concentrated (by a factor of two or greater) in the flyash (behavior expected of Class II elements) or; (BA) the material was concentrated in the bottom ash (by a factor of two or greater). As shown in Table 8-4, almost all of the trace elements had concentrations which were enhanced at the flyash inlet or partitioned equally between bottom ash and flyash streams. In general, the partitioning tendencies found in this test agree with the expectations discussed earlier in this section. However, low NO_x firing implementation shows little, if any, effect on trace element partitioning based on the concentration doubling criteria used.

The trace element data from the coal-fired utility boiler were also examined to determine if partitioning occurs with particle size. Table 8-5 illustrates the presence of this effect at the electrostatic precipitator inlet. The concentrations of Sb, Pb, Zn, Cl, F, sulfate, and ammonium were found to be higher in the finer size particulates. In general, the trace metal behavior is in accordance with partitioning theory. Again though, low NO_x firing seems to have little effect on the tendency to partition with particle size.

In summary, based on the limited test data from one coal-fired utility boiler, low NO_x firing appears to have little effect on the partitioning of trace elements between bottom ash and flyash, and little effect on the segregation of trace species within experimental error (Reference 8-3).

8.1.5 Sulfate Emissions

Ambient sulfate levels have recently become a matter of increasing concern in regions with large numbers of combustion sources, notably boilers, firing sulfur-bearing coal and oil. Although the direct health effects of high ambient sulfate levels are currently unclear (References 8-24 and 8-25), recent thought suggests that sulfates may be more hazardous than SO_2. For this reason, control of primary sulfate emissions is becoming a concern even though primary sulfates (directly emitted) comprise only 5 to 20 percent of ambient sulfate on a regional basis (Reference 8-25).

TABLE 8-4. TRACE ELEMENT PARTITIONING -- BOTTOM ASH/FLYASH -- IN A COAL-FIRED UTILITY BOILER (Reference 8-3)

		Burners Out of Service		Biased Burner Firing	
	Baseline	BOOS I	BOOS II	BIAS I	BIAS II
Antimony	X	X	X	X	X
Arsenic	FA	FA	FA	FA	X
Barium	EQ	EQ	FA	EQ	X
Beryllium	EQ	EQ	EQ	EQ	X
Bismuth	X	X	X	X	X
Boron	FA	FA	FA	X	X
Cadmium	X	X	X	X	X
Chromium	EQ	EQ	EQ	EQ	X
Cobalt	EQ	EQ	EQ	EQ	X
Copper	EQ	EQ	EQ	FA	X
Iron	EQ	EQ	EQ	EQ	X
Lead	FA	FA	FA	FA	X
Manganese	EQ	EQ	EQ	EQ	X
Mercury	EQ	BA	BA	FA	X
Molybdenum	X	X	X	X	X
Nickel	EQ	EQ	EQ	EQ	X
Selenium	X	X	X	X	X
Tellerium	X	X	X	X	X
Thallium	X	X	X	X	X
Tin	X	EQ	X	X	X
Titanium	EQ	EQ	EQ	EQ	X
Uranium	X		X	X	X
Vanadium	EQ	EQ	EQ	EQ	X
Zinc	FA	FA	FA	FA	X
Zirconium	BA	BA	BA	BA	X
Chloride	EQ	EQ	EQ	EQ	X
Fluoride	FA	EQ	BA	FA	X
Cyanide	X	X	X	X	X
Nitrate	X	BA	X	X	X
Sulfate	FA	FA	FA	FA	X
Ammonium	X	FA	FA	X	X

EQ - Material partitioned about equally between bottom ash and flyash
FA - Material preferentially concentrated in flyash
BA - Material preferentially concentrated in bottom ash
X - Insufficient data.

TABLE 8-5. TRACE SPECIES PARTITIONING WITH PARTICLE SIZE -- ESP INLET OF A COAL-FIRED UTILITY BOILER (Reference 8-3)

		Burners Out of Service		Biased Burner Firing	
	Baseline	BOOS I	BOOS II	BIAS I	BIAS II
Antimony	2	2	2	X	2
Arsenic	2	X	X	X	X
Barium	0	0	1	0	0
Beryllium	0	0	0	0	0
Bismuth	X	X	X	X	X
Boron	X	X	X	X	X
Cadmium	X	X	X	X	X
Chromium	0	0	0	0	0
Cobalt	0	0	0	0	0
Copper	0	0	0	0	0
Iron	0	0	0	0	0
Lead	2	2	2	0	0
Manganese	0	0	0	0	0
Mercury	0	2	0	0	1
Molybdenum	X	1	X	X	X
Nickel	0	0	0	0	0
Selenium	X	X	X	X	X
Tellerium	2	2	1	1	1
Thallium	X	X	X	X	X
Tin	0	X	X	X	1
Titanium	0	0	0	0	0
Uranium	X	X	X	X	0
Vanadium	0	0	0	0	0
Zinc	2	2	2	0	0
Zirconium	0	2	1	2	2
Chloride	2	2	2	0	2
Fluoride	0	2	2	0	0
Cyanide	X	X	X	X	X
Nitrate	X	X	X	X	X
Sulfate	0	2	2	2	0
Ammonium	X	X	X	2	2

0 - No significant separation
1 - Concentration enhancement in >3 μm fraction
2 - Concentration enhancement in <3 μm fraction.
X - Insufficient data.

Since approximately 98 percent of the sulfur introduced into a utility boiler appears in flue gas as an oxide, applying NO_x controls would have essentially no effect on total SO_x emissions. However, effects on the emitted (SO_3 + particulate sulfate)/SO_2 ratio can be significant. Specifically, combustion conditions which limit local oxygen concentrations would be expected to decrease the extent of SO_2 to SO_3 oxidation. Thus applying low excess air firing and off stoichiometric combustion to control NO_x should also lower SO_3 and sulfate emissions.

Confirming data, though sparse, do exist. Recent measurements have demonstrated the expected dependence on sulfate emissions on boiler excess air levels. Bennett and Knapp (Reference 8-26) have shown that particulate sulfate emissions increase with increasing boiler excess O_2 in oil-fired powerplants. Homolya, et al. (Reference 8-27) report a similar increase in sulfate emissions as a percentage of total sulfur emissions with increasing excess O_2 in coal-fired boilers. Their data, shown in Figure 8-3, show a linear relationship between the sulfate fraction of emitted sulfur and boiler excess O_2. Still the data of Crawford, et al. (Reference 8-27) from coal-fired utility boilers, Table 8-6, indicate that SO_3 emissions are relatively unaffected by low NO_x firing, considering the accuracy of the measurement techniques, at these low concentrations.

Sulfur emissions, under baseline and low NO_x (biased burner firing and burners out of service) firing modes, were examined during the 180 MW coal-fired tangential boiler test in the NO_x EA program (Reference 8-3). Unfortunately, due to limited coal supplies, the coal sulfur contents were not constant throughout the test program, as noted in Table 8-7. Nevertheless, the data do indicate that the SO_2/SO_3 ratio is not strongly affected by low NO_x firing. Furthermore, the data also show that levels of sulfate in the ash samples are higher in the smaller size particulates, regardless of firing mode. This is seen in the progressively higher sulfate levels in the direction of flue gas flow and also in the comparison of sulfate loading on different size particulate samples collected by the Source Assessment Sampling System (SASS) train. Table 8-7 also indicates that low NO_x firing may also decrease the total sulfate emissions in the flue gas.

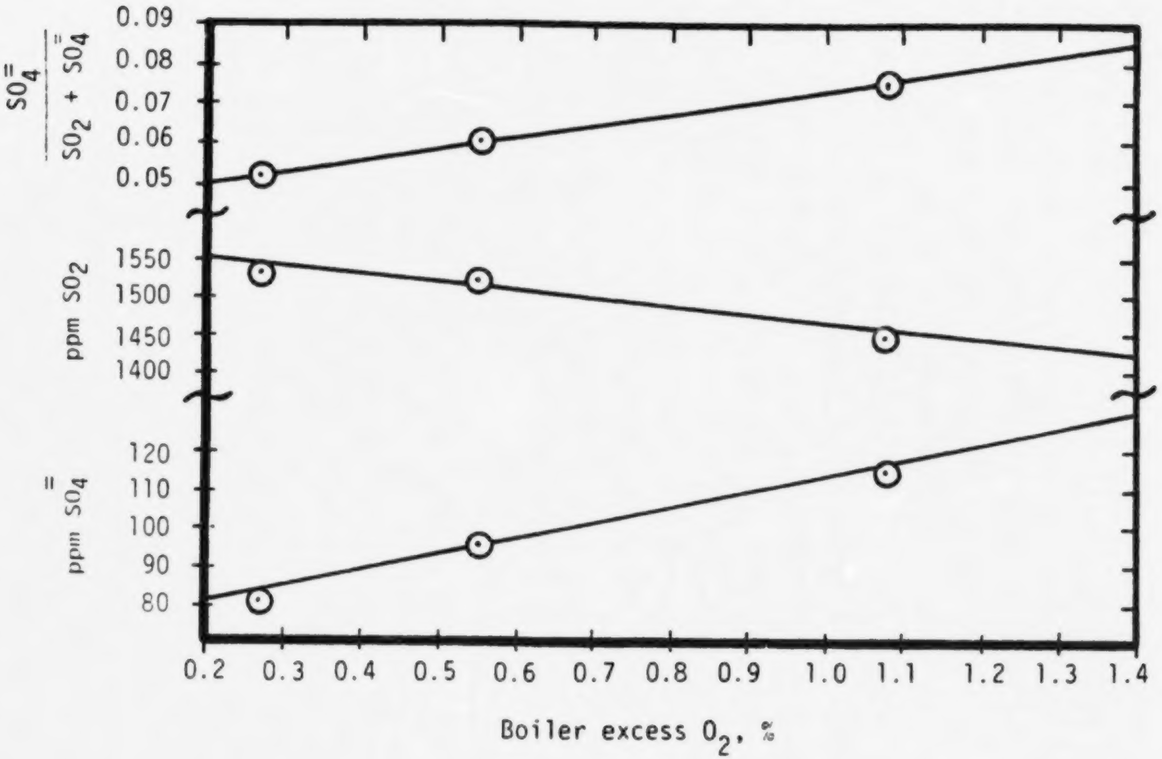

Figure 8-3. SO_2 conversion vs. excess oxygen in coal-fired utility boilers (Reference 8-27).

TABLE 8-6. SO_x EMISSIONS FROM COAL-FIRED UTILITY BOILERS (Reference 8-28)

	O_2 (%)		SO_2	SO_3
	Boiler Exit	Stack	ppm Corrected to 3% O_2	
Baseline	2.9	6.8	944	28
Low Excess Air	1.55 1.5	5.7	948 1,000 Avg 974	13.5 35.9 Avg 25
Off Stoichiometric Combustion	3.1 3.4	7.72 7.1	1,010 968 Avg 989	14.0 13.9 Avg 14

TABLE 8-7. SULFUR SPECIES FROM 180 MW TANGENTIAL COAL-FIRED UTILITY BOILER

Test	Units		Baseline		BIAS I		BOOS II	
Heat Input MW			227.1		229.2		209.8	
Coal-Sulfur	%	(μg/J)	2.19	(0.834)	1.75	(0.664)	2.13	(0.804)
Bottom Ash Sulfate	μg/gm	(μg/J)	500	(7.46×10^{-4})	530	(7.68×10^{-4})	400	(5.58×10^{-4})
Flue Gas - Cont. Monitor	SO_2 ppm at 3% O_2	(μg/J)	2059	(1.75)	1527	(1.30)	1865	(1.59)
Mechanical Collector Ash Sulfate	μg/gm	(μg/J)	1700	(7.75×10^{-3})	1000	(4.42×10^{-3})	1300	(5.65×10^{-3})
ESP Inlet - Method 8								
Particulate - Sulfate	μg/gm	(μg/J)	7800	(1.1×10^{-2})	4500	(5.6×10^{-3})	3000	(3.9×10^{-3})
SO_2	μg/dscm	(μg/J)	4.4×10^{-6}	(1.55)	3.4×10^{6}	(1.19)	3.9×10^{6}	(1.48)
SO_3	μg/dscm	(μg/J)	1.6×10^{4}	(5.6×10^{-3})	1×10^{4}	(3.5×10^{-3})	1×10^{4}	(3.8×10^{-3})

TABLE 8-7. Concluded

Test	Units		Baseline		BIAS I		BOOS II	
ESP Inlet - SASS								
10 + 3 μm - Sulfate	μg/gm	(μg/J)	4100	(4.44×10^{-3})	1900	(2.48×10^{-3})	3800	(3.62×10^{-3})
1 μm + filter - Sulfate	μg/gm	(μg/J)	7300	(2.34×10^{-3})	8400	(5.66×10^{-4})	9200	(2.55×10^{-3})
ESP Hopper Ash								
Sulfate	μg/gm	(μg/J)	5200	(6.02×10^{-3})	4600	(5.41×10^{-3})	4400	(4.71×10^{-3})
ESP Outlet - Method 8								
Particulate - Sulfate	μg/gm	(μg/J)	37800	(8.6×10^{-3})	18200	(4.4×10^{-3})	60500	(1.1×10^{-2})
SO_2	μg/dscm	(μg/J)	4.2×10^6	(1.50)	3.5×10^6	(1.25)	4.2×10^6	(1.57)
SO_3	μg/dscm	(μg/J)	1.2×10^4	(4.3×10^{-3})	1.1×10^4	(3.9×10^{-3})	1.2×10^4	(4.5×10^{-3})
ESP Outlet - SASS								
10 + 3 μm - Sulfate	μg/gm	(μg/J)	7800	(7.21×10^{-4})	5300	(7.23×10^{-4})	--	--
1 μm + filter - Sulfate	μg/gm	(μg/J)	12000	(1.62×10^{-3})	6400	(6.57×10^{-4})	4900	(7.83×10^{-4})

In comparing the sulfate analyses of the SASS and EPA Method 8 samples, it should be noted that the Method 8 data include any condensed material in the sampling probe wash while the SASS data account only for sulfate on the particulate. Details of the test procedures and results are given in Reference 8-3. These findings on sulfur emissions, though based on limited data, are worth noting as the sulfur mass balance closure around the 180 MW unit was greater than 90 percent.

The use of post combustion ammonia injection for NO_x control could possibly lead to significantly increased primary sulfate emissions. Under normal conditions, the pH of near plume liquid droplets is low, approximately 3. At this pH, SO_2 solubility is low. However, if sufficient quantities of a basic specie, such as ammonia, were present to neutralize these droplets, SO_2 solubility would increase dramatically. This could lead to significant amounts of sulfate production through solution catalysis in the near plume (Reference 8-29). Further work is needed in this area before any conclusions can be substantiated.

The problem of acid smut emissions, or sulfate fallout, also deserves some discussion here. Sulfate fallout emissions of large, highly acidic carbonaceous particulate have been experienced recently from several residual oil-fired utility boilers in the U.S. This fallout is extremely corrosive and since the acidic particulate is of large size (up to 100 m), leads to fallout in the vicinity of the powerplant. Sulfate fallout is thus of concern for potential impact on both human health and welfare. Acid fallout has been experienced for many years in Europe due to the practice of firing heavy oil units at lower levels of excess air than is common in the U.S. (References 8-30 through 8-34).

Recently the problem has occurred when certain NO_x controls, notably off stoichiometric combustion combined with low excess air, are implemented on residual oil-fired units. It also invariably occurs in boilers which were originally designed to fire natural gas, but have been converted to oil firing because of fuel availability problems.

The exact reasons for the appearance of acid fallout are not clearly understood. However, it is clear that they are related to air heater design and the resulting final flue gas temperature. Since natural gas contains very little sulfur, acid mist condensation in and downstream of the air heaters has never been a concern. Therefore, air heaters in gas-fired boilers have been designed to give lower flue gas temperatures than corresponding air heaters in oil-fired units. However, when these same gas-fired units are switched to oil firing, it is possible for flue gas temperatures downstream of the air heater to approach the acid dew point. In the absence of particulate emissions, flue gas sulfuric acid could then condense and reevaporate through the ductwork and stack until ultimately emitted as a finely dispersed mist.

The appearance of fallout when implementing NO_x controls which enhance the production of soot particles suggests the possible next step in the smut formation mechanism. In the presence of sufficient particulate, flue gas sulfuric acid condenses onto particle surfaces in sufficient amounts to cause particle agglomeration. Agglomerated particles then deposit onto ductwork walls. These deposits continue to grow through further agglomeration until they become large enough to fall off the wall. Thus, emissions of large acidic particulate occur.

In light of the above, sulfate fallout emissions have been viewed as a combined sulfate production problem and particulate production problem. Attacks on the problem have included both reduction of acid formation and/or condensation and suppression of carbon formation or agglomeration. Table 8-8 summarizes process modifications used or proposed in Europe and the U.S. (References 8-31 through 8-34). It appears that incremental sulfate fallout emissions can be suppressed if addressed during control development. The potential for acid fallout emissions should be considered when implementing NO_x controls on heavy oil-fired boilers with air preheaters and without particle collection devices.

In summary, the postulated, and in some cases demonstrated, effects of most NO_x combustion controls on primary sulfates are to decrease emissions or leave them unchanged. However, since there are insufficient data to fully substantiate any real conclusion, it seems appropriate to consider incremental sulfate emissions due to NO_x combustion modifications of questionable concern, except in the case of acid fallout and use of post combustion ammonia injection. Because ammonia injection may significantly increase near plume sulfate production through solution chemistry, its effects on residual sulfate should be considered of definite concern.

TABLE 8-8. SUMMARY OF PROCESS MODIFICATIONS TO REDUCE SULFATE FALLOUT

Principle	Candidate Techniques	Size Range Affected	Comments
1. Suppress buildup of acid smut	Frequent or continuous soot blow	Large particles	Acid smuts emitted in smaller, dispersable, size range; successfully tested at Eastern Utility; promising option
2. Prevent acid condensation	Reduced air preheat	Large particles	Reduced efficiency; possible smut buildup in stack at reduced size range
3. Neutralize acid smut	Additives: dolomite, limestone, MgO, NH_3	Large and small particles	Reduces (50%) but doesn't eliminate acid emissions; additives increase particle loading
4. Suppress SO_3 formation	Reduced excess air	Large and small particles	Increased efficiency; increased carbon and CO emissions; limited by NO_x control techniques
	Reduced load	Large and small particles	Not cost effective
	Reduced catalytic activity of superheater	Large and small particles	Additive coating is partially effective; operational problems
	Reduced sulfur in fuel; mixed distillate/resid. firing	Large and small particles	Distillate availability uncertain
5. Reduce carbon emissions	Increased excess air	Large and small particles	Reduced efficiency; increased SO_3
	Better firebox mixing	Large and small particles	Limited by NO_x controls
6. Particle collection	Cyclone, ESP or baghouse	Large and small particles	Effective but costly

8.1.6 Organic Emissions

The term organic emissions as used here is defined to mean those organic compounds which exist as a condensed phase at ambient temperature. Thus they are organics which are either emitted as "carbon on particulate" or condense onto emitted particulate in the near-plume of a stack gas. These compounds, with few exceptions, can be classified into a group known variously as polycyclic organic matter (POM) or polynuclear aromatic hydrocarbons (PNA or PAH).

POM production is generally only a minor concern in gas-fired systems, of some concern in oil-fired sources, and of greater concern in coal-fired equipment. Like CO and HC emissions, POM emissions are the result of incomplete combustion. Since NO_x combustion controls can lead to inefficient combustion, if not carefully applied (especially low excess air and off stoichiometric combustion), applying these controls can potentially lead to increased POM production.

Supporting data, however, are very limited, largely because of the difficulty of sampling flue gas streams for POM and of accurately assaying samples for individual POM species. Thompson et al., recently reported the effects of staged combustion and flue gas recirculation on POM emissions from a coal-fired utility boiler (Reference 8-8). Their data, shown in Table 8-9, seem to indicate that POM emissions do increase with off stoichiometric combustion, but are relatively unaffected by flue gas recirculation alone. However, the authors state that the sampling and laboratory analysis procedures used in obtaining the data varied over the sample set. Thus, the conclusion that POM emissions may be increased with low NO_x firing should only be considered tentative. In another study, Bennett and Knapp (Reference 8-26) attempted to investigate the effects of boiler excess O_2 on POM emissions from an oil-fired utility boiler. They found that particulate carbon content increased with decreasing excess O_2. However, because POM assay data varied widely, even for baseline condition analyses, no conclusion regarding POM emissions was possible.

The organic analyses from low NO_x firing at the 180 MW unit tested in the NO_x EA program yielded only general conclusions. There was not a sufficient amount of organic material in any of the samples to permit significant species identification. However, the analyses do show that total organic emissions were slightly higher under low NO_x (BOOS) firing.

TABLE 8-9. SUMMARY OF POM EMISSIONS FROM HATFIELD UNIT NO. 3 MEASURED UPSTREAM OF ESP (Reference 8-8)

Substance	Baseline	BOOS Operation		FGR Operation		BOOS + FGR Operation	
	μg/MJ	μg/MJ	Percent Difference from Baseline	μg/MJ	Percent Difference from Baseline	μg/MJ	Percent Difference from Baseline
Anthracene/Phenanthrene	54.3	54.6	+0.5	44.3	-18.5	70.1	+29.1
Methyl Anthracenes	16.3	14.8	-9.3	27.2	+66.9	30.0	+83.7
Fluoranthene	15.6	33.6	+114.5	7.49	-52.1	13.3	-15.2
Pyrene	4.55	15.8	+247.9	7.11	+56.3	14.3	+214.6
Chrysene/Benz(a)Anthracene	0.09	--	--	--	--	--	--
Total POM	90.9	18.8	+30.7	86.1	-5.3	127.7	+40.5

Table 8-10 shows that the organic material concentrations in the bottom ash, mechanical collector ash, electrostatic precipitator ash, and the flue gas outlet (vapor phase) were higher for low NO_x firing. The flue gas outlet particulate organic content was slightly higher under baseline conditions. However, that effect is overshadowed by the significantly larger (order of magnitude) vapor phase organic emissions under low NO_x firing. Thus, although organic emissions were low in these tests, there is a need to conduct more quantitative organic analyses due to the high relative hazard of certain organic compounds.

8.1.7 Source Analysis Model

To help quantify the potential change in environmental impact of a utility boiler which switches from baseline to low NO_x firing, a source analysis model, SAM IA (References 8-1 and 8-2), was applied to the effluent data from the 180 MW coal-fired utility boiler tested in the NO_x EA program. EPA has been developing a series of source analysis models to define methods of comparing emission data to environmental objectives, termed Multimedia Environmental Goals (MEG's) (Reference 8-35). The model selected for the level of data detail obtained from the utility boiler tests was SAM IA, designed for rapid screening purposes. As such, it includes no treatment of pollutant transport or transformation. Goal comparisons employ threshold effluent stream concentration goals, termed discharge multimedia environmental goals (DMEG's).

For the purposes of screening pollutant emissions data to identify species requiring further study, a discharge severity (DS) is defined as follows:

$$DS_i = \frac{\text{Concentration of Pollutant i in Effluent Stream}}{\text{DMEG of Pollutant i}}$$

The DMEG value, the threshold effluent concentration, is the maximum pollutant concentration considered safe for occupational exposure. When DS exceeds unity, more refined chemical analysis may be required to quantify specific compounds present.

TABLE 8-10. ORGANIC EMISSIONS FROM A 180 MW COAL-FIRED UTILITY BOILER (Reference 8-1)

Organic Material in Ash Streams

Firing Mode	Sample	Equivalent Organics in Ash Stream	
		μg/gm	μg/J
Baseline	Bottom Ash	1.5	2.2×10^{-6}
	Mechanical Collector	<1.3	$<5.9 \times 10^{-6}$
	Electrostatic Precipitator	1.4	1.6×10^{-6}
BOOS	Bottom Ash	4.2	5.9×10^{-6}
	Mechanical Collector	3.2	1.4×10^{-5}
	Electrostatic Precipitator	6.7	7.2×10^{-6}

Organic Material in Flue Gas Outlet (ESP Outlet)

Firing Mode	Sample	Equivalent Organics in Flue Gas	
		μg/m^3	μg/J
Baseline	Particulate	60	2.1×10^{-5}
	Vapor Phase	75	2.7×10^{-5}
BOOS	Particulate	44	1.6×10^{-5}
	Vapor Phase	788	2.9×10^{-4}

To compare waste stream potential hazards, a weighted discharge severity (WDS) is defined as follows:

$$\text{WDS} = \left(\sum_i \text{DS}_i\right) \times \text{Stream Mass Flowrate},$$

where the DS_i are summed over all species analyzed. The WDS is an indicator of output of hazardous pollutants and can be used to rank the needs for controls for waste streams. It can also be used as a preliminary measure of how a pollutant control, say a combustion modification NO_x control, affects the overall environmental hazard of the source. An extensive exposition of SAM IA and list of DMEG's are presented in References 8-1, 8-2, and 8-36 and will not be repeated here.

SAM IA was applied to the analysis results from the 180 MW unit. Table 8-11 summarizes the boiler outlet flue gas effluent concentrations (ESP outlet for particulates and trace species) for baseline and low NO_x firing. Two levels of NO_x reduction were tested. Retrofit bias firing gave a 32 percent NO_x reduction, and operation with the upper row of nozzles on air only gave a 38 percent NO_x reduction. The furnace efficiency either remained constant or increased slightly (due to lower excess air) under low NO_x operation. There was no appreciable increase in carbon-in-flyash with NO_x controls. It should be mentioned that these tests were for short periods, so the long term operability under these low NO_x conditions was not necessarily validated.

For the majority of elements listed in Table 8-11, the changes in emission rates between baseline operation and low NO_x firing were within the accuracy of the analysis and are not judged to be significant. Notable exceptions are the leachable nitrates and ammonium compounds. Here, it is possible that local fuel rich conditions under low NO_x operation suppresses reduced nitrogen compound oxidation normal to baseline operation. As mentioned earlier, organic species analyses were inconclusive, though in total organic emissions increased with low NO_x firing. The analysis results for the other waste streams -- cyclone ash, ESP ash, and bottom ash slurry -- are all presented in Reference 8-1. Table 8-12 lists the DS values for those inorganic species or compounds where $DS \geq 1$. It is evident that the gaseous pollutants, particularly SO_2 and NO_x dominate the

TABLE 8-11. ANALYSIS RESULTS FOR A 180 MW TANGENTIAL COAL-FIRED UTILITY BOILER: FLUE GAS, INORGANICS

TEST	BASELINE	BIAS (Test 1)	BOOS (Test2)
Heat input (% of baseline)	100	100.9	92.4
Emissions $\frac{\mu g}{m^3}$ dry			
NO_x(ppm @ 3% O_2 dry)	1.16×10^6 (490)	7.35×10^5 (336)	6.54×10^5 (304)
SO_2(ppm @ 3% O_2 dry)	4.18×10^6 (1668)	3.5×10^6 (1354)	4.21×10^6 (1591)
SO_3(ppm @ 3% O_2 dry)	1.45×10^4 (3)	1.32×10^4 (3)	9580 (3)
CO^x(ppm @ 3% O_2 dry)	3.07×10^4 (28.6)	4.58×10^4 (35.0)	3.19×10^4 (21.7)
CO_2(%)	2.72×10^8 (13.9)	2.82×10^8 (14.4)	2.86×10^8 (14.6)
O_2	(5.2)	(4.7)	(4.4)
Particulate	6.3×10^5	6.7×10^5	4.3×10^5
Antimony	3.9	<2.6	<2.6
Arsenic	95	78	81
Barium	2.25×10^3	1.7×10^3	1.5×10^3
Beryllium	9.0	11	7.3
Bismuth	<53	<56	2.3×10^2
Boron	--	--	8.8×10^2
Cadmium	2.3	<2.4	<2.1
Chromium	1.69×10^3	4.8×10^2	2.4×10^3
Cobalt	66	75	89
Copper	2.9×10^2	3.4×10^2	3.2×10^2
Iron	4.5×10^4	3.4×10^4	3.3×10^4
Lead	74	86	51
Manganese	2.4×10^2	1.3×10^2	1.9×10^2
Mercury	1.8	3.1	3.5
Molybdenum	1.5×10^2	<56	8.7×10^2
Nickel	8.4×10^2	1.0×10^3	1.5×10^3
Selenium	10	8.2	5.1
Tellurium	<4.1	<4.0	<3.7

TABLE 8-11. Concluded

TEST	BASELINE	BIAS (Test 1)	BOOS (Test2)
Thallium	<2.6	<2.7	<2.1
Tin	<6.4	<6.7	<5.1
Titanium	6.1×10^3	5.7×10^3	3.6×10^3
Uranium	<3.9	44	<2.1
Vanadium	2.6×10^2	2.3×10^2	1.6×10^2
Zinc	4.3×10^2	5.9×10^2	8.4×10^2
Zirconium	1.9×10^2	2.6×10^2	6.8×10^2
Chloride	2.7×10^2	4.1×10^2	8.6×10^2
Fluoride	84	3.5×10^2	1.2×10^2
Cyanide	<1.3	0.3	<1.3
Nitrate	<3.9	24	7.7×10^2
Sulfate	6.5×10^3	3.9×10^3	2.1×10^3
Ammonium	<5.3	7.2	1.4×10^2
Coal Analysis			
C%	63.13	63.46	64
H%	4.27	4.24	4.23
O%	7.34	7.97	7.11
N%	1.38	1.13	1.38
S%	2.19	1.75	2.13
H_2O%	2.04	2.34	2.58
Ash%	19.60	19.09	18.49
HHV, J/g	26288	26363	26521
Btu/lb	11302	11334	11402

TABLE 8-12. FLUE GAS DISCHARGE SEVERITY -- INORGANICS: 180 MW TANGENTIAL COAL-FIRED UTILITY BOILER

	BASELINE	BIAS	BOOS
NO_x	129	84	73
SO_2	322	269	324
SO_3	15	13	9.6
CO	0.77	1.1	0.80
CO_2	30	31	32
Be	4.5	5.5	3.6
Ba	4.5	3.4	3.0
As	48	39	41
Ti	1	0.95	0.60
N (Mainly NH_4)	0.07	0.22	6.1
SO_4	6.5	3.9	2.1
Chlorides	0.68	1	2.1

TABLE 8-13. TOTAL WEIGHTED DISCHARGE SEVERITY (g/s) -- INORGANICS: 180 MW TANGENTIAL COAL-FIRED UTILITY BOILER

	BASELINE	BIAS	BOOS
Flue Gas	4.3×10^7	3.5×10^7	3.7×10^7
Cyclone Ash	1.9×10^4	1.6×10^4	1.6×10^4
ESP Ash	6.1×10^3	6.1×10^3	5.1×10^3
Bottom Ash Slurry	5.7×10^4	5.3×10^4	4.2×10^4
Total	4.3×10^7	3.5×10^7	3.7×10^7

potential toxicity of the flue gas stream. Of the trace metals, arsenic shows the highest DS, but none of the metals show any large change under low NO_x conditions. As may be expected, SO_3 decreased under low NO_x operation and reduced N compounds increased.

The total weighted discharge severity for the inorganic component of four waste streams of the boiler are compared in Table 8-13. Clearly the flue gas stream dominates the TWDS, with the solid streams three orders of magnitude potentially less toxic, according to the model. With low NO_x firing, the flue gas stream TWDS is reduced, primarily due to the decrease in NO_x concentration. The TWDS's for the other waste streams either decreased or were constant when going to low NO_x firing. As mentioned earlier, more data are needed for waste stream organic composition before the degree of hazard for organic compounds, relative to inorganics, can be estimated.

From the application of SAM IA to the admittedly sparse data base of a few short tests on a single coal-fired boiler, the results indicate that NO_x controls are generally beneficial, reducing the overall adverse environmental impact of waste streams. These results, along with the general indications from other reported tests, tend to confirm that combustion modification NO_x controls are environmentally sound, though work remains to confirm and correct any potential adverse environmental impacts from incremental emissions.

8.1.8 Evaluation and Summary

Based on the previous discussions, NO_x control techniques and pollutants can be classified into one of the following three groups according to potential for increased emissions:

- High potential emissions impact, where the data clearly show that applying the NO_x control results in significantly increased emissions of a specific pollutant
- Intermediate potential emissions impact, where the NO_x control could conceivably cause increased pollutant emissions, but confirming data are lacking, contradictory, or inconclusive
- Low potential emissions impact, where the data clearly show that specific pollutant emission levels decrease or do not change when the NO_x control is applied, or a similar conclusion, is indicated even though data are lacking

These groupings appear in Table 8-14.

As Table 8-14 illustrates, applying preferred NO_x combustion controls to boilers should have few adverse effects on incremental emissions of CO, vapor phase hydrocarbons, or particulates. It is true that indiscriminantly lowering excess air can have drastic effects on boiler CO emissions, and that particulate emissions can increase with off stoichiometric combustion and flue gas recirculation. However, with suitable engineering during development and implementation of these modifications, adverse incremental emissions problems can be minimized. In contrast, residual emissions of sulfate, organics, and trace metals have intermediate to high potential impact associated with applying almost every combustion control. For trace metal and organic emissions, substantiating data are largely lacking, but fundamental formation mechanisms give cause for justifiable concern. Indeed, the 180 MW coal-fired utility boiler test indicated a marked increase in organic emissions with off stoichiometric combustion. In the case of sulfate emissions, fundamental formation mechanisms suggest that these emissions should remain unchanged or decrease with all controls except ammonia injection. Data from the recent utility boiler test lend support to this hypothesis in the case of off stoichiometric combustion. However, complex interactive effects are difficult to elucidate, and sulfates are considered sufficiently hazardous to justify expressing some concern in the present absence of conclusive data. The potential effects of postcombustion ammonia injection on plume sulfate formation deserve special attention.

The incremental emission evaluations of Table 8-14 are not intended to signify any potential for adverse environmental impact. Rather, the evaluation notes control/pollutant combinations for which emissions may increase due to the use of NO_x controls. Evaluation of potential adverse impact requires comparison of the source generated ambient pollutant concentration with an upper limit threshold concentration of the pollutant based on health or ecological effects. A preliminary attempt at such a comparison has been made in Section 8.1.7.

In general, the data on incremental multimedia emissions due to NO_x controls are still very sparse. More data are available for flue gas emissions than for liquid or solid effluent streams. Even so, the only data which allow quantified conclusions are for emissions of criteria pollutants

TABLE 8-14. EVALUATION OF INCREMENTAL EMISSIONS DUE TO NO_x CONTROLS APPLIED TO BOILERS

NO_x Control	Incremental Emission						
	CO	Vapor Phase HC	Sulfate	Particulate	Organics	Segregating Trace Metals	Nonsegregating Trace Metals
Low Excess Air	++	0	+	0	++	+	0
Off Stoichiometric Combustion	0	0	0	0	++	+	0
Flue Gas Recirculation	0	0	+	+	+	+	+
Reduced Air Preheat	0	0	+	0	+	0	+
Reduced Load	0	0	+	0	+	0	0
Water Injection	0	0	+	+	+	0	0
Ammonia Injection	0	0	++	+	0	+	0

Key: ++ denotes having high potential emissions impact
+ denotes having intermediate potential emissions impact, data needed
0 denotes having low potential emissions impact

with the major control applications. Data on sulfates, trace metals, and organics (POM) are sparse, experimentally uncertain and highly dependent on fuel properties. Incremental emissions from liquid and solid effluent streams and during transient or nonstandard operation are almost nonexistent. Because of this, they have generally been excluded in the present evaluation.

Emissions of CO, HC, particulate (smoke), and SO_3 with or without NO_x controls have been constrained in the past for operational reasons rather than environmental impact. CO, HC, and smoke emissions reduce efficiency and may present a safety hazard. SO_3 leads to acid condensation and corrosion. All of these emissions are sensitive to combustion process modifications for NO_x control. With the exception of SO_3, incremental emissions tend to increase with NO_x controls, particularly low excess air and off stoichiometric combustion. Development experience has shown, however, that with proper engineering these emissions can generally be constrained under low NO_x conditions. This is particularly true for factory-installed controls on new equipment. In this case, the flexibility for applying NO_x controls with minimal adverse impact is greater than for retrofit on existing equipment. In light of this situation, incremental emissions are seen more as a constraining criteria to be addressed during control development than as an immutable consequence of low NO_x firing. Moreover, the constraint on emissions for satisfactory operational performance is oftentimes more stringent than the constraint for acceptable environmental impact.

The situation for other flue gas pollutants is more uncertain. There is concern that conventional combustion process modifications -- low excess air, off stoichiometric combustion, flue gas recirculation -- will increase emissions of organics and segregating trace metals from sources firing coal or residual oil. It should be noted, however, that this conclusion is based on sparse data or, lacking that, on fundamental speculation. Clearly, more data are needed.

In conclusion, there is reasonable concern that NO_x controls will increase incremental emissions of some pollutants. More data are still needed to determine if incremental emissions have a significant environmental impact and to suggest corrective action if needed.

8.2 ENERGY IMPACT

Changes in energy consumption with application of combustion modification NO_x controls is one of many potential process impacts. Although these process impacts are reviewed in the next subsection, energy impact is of such paramount importance (since it can account for up to half of the cost-to-control) that it warrants a separate review.

The largest potential energy impact of combustion modifications is their effect upon boiler thermal efficiency. Another significant source of energy impact is the change in fan power requirements caused by these controls. Boiler control systems installed for low NO_x operation also increase electricity and instrument air requirements, but the energy impact is usually minimal. Section 6 has already discussed on a boiler-by-boiler basis the energy impacts of applied NO_x controls. As noted there, with proper engineering and implementation, there should be no major adverse energy impacts with preferred combustion modifications. A review of that analysis follows.

Applying low excess air (LEA) firing not only results in a small decrease in NO_x emissions but also an increase in boiler efficiency through reduced sensible heat loss out the stack. For this reason the technique has gained acceptance and has become more a standard operating procedure than a specific NO_x control method in both old and new units.

The other commonly applied combustion modifications, off stoichiometric combustion (OSC) and flue gas recirculation (FGR), often lead to decreases in boiler efficiency when implemented on a retrofit basis. Off stoichiometric combustion usually increases excess air requirements resulting in decreases in efficiency of up to 0.5 percent. Unburned fuel losses either due to OSC or FGR may cause a decrease in efficiency of up to 0.5 percent. If a substantial increase in reheat steam attemperation is required due to OSC or FGR, cycle efficiency losses of up to 1 percent may occur. Increased fan power requirements due to OSC or FGR will also impact efficiency, resulting in losses of up to 0.2 to 0.3 percent. No significant energy impact is expected with low NO_x burners (LNB), either retrofit or new installation.

Ammonia injection requires energy for the injectors, NH_3, handling equipment, and carrier gas, resulting in an energy loss of about 0.25 percent. Moreover, the impact of increased ammonia consumption on the nationwide energy situation may be significant since ammonia is synthesized primarily from natural gas. These impacts are discussed elsewhere (Reference 8-37).

Other combustion modification techniques, water injection and reduced air preheat, can impose quite significant energy penalties on boiler operation, with decreases in efficiency from 5 to 10 percent. As a consequence, these techniques are quite unpopular, and have found little acceptance.

In summary, the decreases in boiler efficiency (increases in energy consumption) discussed above for the preferred NO_x control techniques (OSC, FGR, and LNB) represent upper estimates when applied on a retrofit basis. These same combustion modifications are not expected to adversely affect unit efficiency when designed in as part of a new unit. This illustrates that with proper engineering and development, combustion modification NO_x controls can be incorporated into new unit designs with no significant adverse energy impacts.

8.3 PROCESS IMPACTS

Low NO_x operation of utility boilers has been a source of concern among utility plant operators due to potential adverse effects associated with NO_x control techniques. The impact of combustion modifications on boiler performance, operation, and maintenance has been discussed in detail in the process analysis of Section 5. The major concerns are summarized briefly below.

8.3.1 Efficiency

This potential impact has just been reviewed in the previous subsection, which concluded that preferred NO_x controls should not cause significant adverse energy impacts on new units. However, for retrofit applications, decreases in boiler efficiency, though minor, are of concern because of the rapidly rising cost of fuel.

8.3.2 Corrosion

Corrosion is potentially a major problem with off stoichiometric combustion (OSC) on coal-fired boilers because of possible local reducing conditions when staging. Furnaces fired with certain Eastern U.S. bituminous coals with high sulfur contents may be especially susceptible to corrosion attack under reducing atmospheres. Tests with corrosion coupons show wide scatter in data but generally indicate no significant increase in corrosion due to OSC. Current EPA-sponsored long-term tests on actual tube walls should provide more definitive conclusions. There have been no reports of corrosion in oil-fired boilers due to OSC. No corrosion problems are expected with either oil- or gas-fired boilers.

8.3.3 Slagging and Fouling

In coal-fired equipment operating under OSC there has been some concern regarding slagging. Slag usually fuses at a lower temperature under reducing conditions. It was surmised that in certain cases molten, hard to remove slag would form near the burners fired under fuel-rich conditions. In the many tests conducted, however, no increase in slagging has been noted. In oil-fired equipment also no increased fouling has been reported. In gas-fired boilers fouling is a problem when switching from oil to gas as the ash deposited on the walls during oil-firing causes reduced furnace heat absorption and hence, increased furnace outlet gas temperatures.

8.3.4 Derating

Loss in boiler load capacity due to limited coal pulverizer capacity will occur in many coal-fired boilers operated with burners-out-of-service (BOOS). Derates of 10 to 25 percent may occur. For oil-fired boilers on OSC, higher excess air requirements may cause fan capacity limits to be reached in some cases. Although derates due to fan capacity are not common, reductions of up to 15 percent have been reported. With OSC and flue gas recirculation (FGR), excessive tube and steam temperatures may lead to derating, expecially for gas-fired boilers, and in some cases for oil-fired boilers. Derates of as high as 50 percent have been reported with gas-firing immediately after switching from oil firing when the problem is most severe.

8.3.5 Steam and Tube Temperatures

Excessive steam and tube temperatures may be encountered with oil- and gas-firing when operated with OSC and FGR. The problem with tube temperatures are expecially severe with units switched from oil to gas firing. Increased tube failures may occur. Unless the furnace is completely water washed to clean heat transfer surfaces before the switch, derates of up to 50 percent may be required to prevent excessive tube temperatures. Excessive reheat attemperation would necessitate removal of some reheater surface in order to avoid a reduction in cycle efficiency. Superheater surfaces may need to be removed if superheater attemperator capacities are exceeded. Ususally removal of reheater or superheater surface must be accompanied by adding to the economizer surface if boiler efficiency is to be maintained. No excessive steam and tube temperatures have been reported with coal-firing.

8.3.6 Flame Instability and Vibrations

Problems with flame instability and furnace fan or duct vibrations often occur with FGR operation on oil- and gas-fired boilers. Changes in burner geometry and design are usually required to correct flame instability and associated furnace vibration problems. Fan and duct vibration problems may be avoided by careful design. In some cases, unit startup and load pickup response will be altered due to FGR fan preheating requirements. No instability or vibration problems have been reported with coal firing.

8.3.7 Particulates

On coal-fired boilers, particulate emissions may increase with OSC, although there is wide scatter in the data. Increases are usually around 20 percent on the average, although numbers as high as 50 percent and 100 percent have been reported. Increase in particulates may also increase erosion; but this should show up on corrosion tests, and as mentioned earlier the results of of those tests have been inconclusive. No significant change in particle size distribution has been observed with OSC. With low NO_x burners (LNB) there may be a shift towards smaller particle sizes. An increase in particulate loading or number of smaller particles may require installation of larger or more efficient particulate collection devices. There is very little data on oil-fired boilers, but one test has shown no significant change in particulate loading or size distribution with OSC (Reference 8-10). With gas-fired boilers there should be no problems with particulates.

8.3.8 Auxiliary Equipment

Implementation of low NO_x techniques often impacts the operation of boiler auxiliary equipment. OSC usually increases fan power requirements. Average increases of 10 percent are reported if excess air requirements do not increase substantially. If excess air rises significantly due to OSC operation, F.D. or I.D. fan capacities may be reached. OSC and FGR also affect superheater and reheater attemperation requirements. Again, in some cases, spray attemperation flow limits may be reached. In coal-fired boilers, OSC and LNB can result in increased carbon loss in flyash. Carbon loss may increase by as much as 130 percent. Increased carbon in flyash may have an adverse impact on electrostatic precipitator operation due to changes in flyash resistivity. However, in some tests conducted to measure flyash resistivity, no change was noted due to low NO_x operation.

8.3.9 Other Operational Impacts

Low NO_x operation can impact the safety and control aspects of a boiler. Hazier flames and obscure flame zones associated with OSC firing on oil- and gas-fired boilers ususally requires new flame scanners and detectors. OSC firing also changes minimum air requirements which requires appropriate combustion control modifications. Boilers may also often be more prone to smoke or emit CO emissions under OSC firing requiring greater operator attention. In some cases the boiler may require modified startup procedures, e.g., FGR fan preheating and temperature change limitations.

8.3.10 Maintenance

As most low NO_x techniques are very sensitive to boiler conditions an accelerated maintenance and overhaul schedule may be necessary. Boiler cleaning, burner tuning, checking fuel and air distributions, checking for signs of tube wear or incipient failure, etc., may all need to be carried out at regular intervals to maintain low NO_x operating conditions and prevent serious problems prior to their occurrence.

8.3.11 Concluding Remarks

This subsection has highlighted some of the potential process impacts of combustion modification NO_x controls. They are meant only as a guide to control developers and users to aid in avoiding potential problems. Of course, a particular boiler/control application may have none or only a few of these problems. With proper engineering and implementation, potential adverse process impacts can often be eliminated or minimized.

8.4 ECONOMIC IMPACT

Costs are particularly important in regulated utility economics, especially because all "allowable" costs of doing business are permitted to be recovered from the consumer. Not only is a utility concerned with the impact of a pollution control on the final cost of electricity but also on the impact of the initial outlay of capital. The public utility sector is characterized by the necessity for large aggregations of capital because the enterprises typically require high initial investment costs (Reference 8-38).

Section 7 analyzed costs in detail of several representative applications of combustion modification NO_x controls, both retrofit and new unit application. The following dicussion summarizes that study.

8.4.1 Retrofit Control Costs

Analysis of retrofit control costs is important as there is often a need for controlling NO_x from existing boilers, as part of State Implementation Plans, in response to specific aspects of the Clean Air Act (e.g., the emissions offset program for nonattainment areas). Besides, most of the existing data base on combustion modification NO_x controls is from retrofit demonstrations. Thus, retrofit analysis should provide a good estimate for the cost-to-control, as it is expected that factory installed controls, properly engineered, should cost less.

Table 8-15 lists the representative boiler/retrofit control combinations costed in this study. It was assumed that the units being retrofitted were relatively new, say 5 to 10 years old, with at least 25 years of service remaining. As Table 8-15 shows, overfire air and low NO_x burners were selected as the retrofit control methods for coal-firing. Burners out of service was not necessarily recommeded for coal-fired units, but was included to demonstrate the high cost of derating a unit, as is often the case for pulverized coal units. Burners out of service, and flue gas recirculation through the windbox combined with overfire air were selected as the retrofit control methods for a single wall oil-and gas-fired unit.

Estimated costs for applying the treated NO_x controls, in 1977 dollars, are summarized in Table 8-16. The table shows initial capital investment, annualized capital investment with other indirect costs, annualized direct costs, and total annualized cost to control. The table indicates that the preferred combustion modification generally costs between $0.50 to 0.70/kW-yr to install and operate. One major exception to this is the use of BOOS firing on coal-fired units if derating is required due to insufficient mill capacity. In this instance the high cost of BOOS implementation reflects the need to purchase makeup power, and to account for lost capacity (a 20 percent derate is typical) through a lost capital charge.

TABLE 8-15. BOILER/RETROFIT CONTROL COMBINATIONS COSTED

Boiler Fuel	MCR[a] (MW)	NO_x Control
Tangential/Coal	225	OFA
Opposed Wall/Coal	540	OFA
Opposed Wall/Coal	540	LNB
Opposed Wall/Coal	540	BOOS
Single Wall/Oil, Gas	90	BOOS
Single Wall/Oil, Gas	90	OFA & FGR

[a] Maximum continuous rating in MW of electrical output

TABLE 8-16. SUMMARY OF RETROFIT CONTROL COSTS (1977 DOLLARS)[a]

Boiler/Fuel Type	Initial Investment ($/kW)	Annualized Indirect Operating Cost ($/kW-yr)	Annualized Direct Operating Cost ($/kW-yr)[b]	Total to Cost Control ($/kW-yr)[b]
Tangential/Coal-Fired				
OFA	0.90	0.21	0.32	0.53
Opposed Wall/Coal-Fired				
OFA	0.62	0.16	0.52	0.69
LNB	2.03	0.34	0.06	0.40
BOOS[c]	0.08	5.34	24.78	30.12
Single Wall/Oil- and Gas-Fired				
BOOS	0.30	0.05	0.44	0.49
FGR/OFA	5.71	1.14	1.91	3.05

[a] Based on assumptions given in Section 7 and cost input parameters listed in Appendix E.

[b] Based on 7000 h operating year. Typical costs only.

[c] Assumes twenty percent derate required.

8.4.2 Control Costs for New Units

Estimating the incremental cost of NO_x controls for NSPS boilers is in some respects an even more difficult task than costing retrofits. Certain modifications on new units, through effective in reducing NO_x emissions, were originally incorporated due to operational considerations rather than from a control viewpoint. For example, the furnace of a typical unit designed to meet 1971 NSPS has been enlarged to reduce slagging potential. But this also reduces NO_x due to the lowered release rate. Thus, since the design change would have been implemented even without the anticipated NO_x reduction, the cost of that design modification should not be attributed to NO_x control.

Babcock & Wilcox and Foster Wheeler have estimated the cost of preferred NO_x controls for new coal-fired boilers using low NO_x burners and overfire air. Both manufacturers indicate incremental costs in the \$1.75 to \$2.80/kW range, or \$0.28 to 0.43/kW-yr annualized, for a typical NSPS boiler. These costs are discussed in detail in Section 7.

8.4.3 Cost Effectiveness of Controls

Combustion modifications represent cost-effective, demonstrated means of NO_x control for utility boilers, reducing NO_x emissions 20 to 60 percent at relatively low cost, usually less than 1 percent of the cost of electricity. Furthermore, the initial capital cost is usually less than 1 percent of the cost of the boiler. Table 8-17 summarizes projected control requirements for alternative NO_x emission levels. Control requirements are recommended to achieve a given NO_x emission level. These control levels combined with the cost of control column, complete the cost-effectiveness picture.

Compared to the \$0.30 to \$0.50/kW-yr cost of preferred combustion modification controls for new coal-fired boilers, alternative NO_x control techniques, ammonia (NH_3) injection and selective catalytic reduction (SCR), neither of which represent demonstrated technology, are projected to cost significantly more: \$2.50 to \$3.40/kW-yr for NH_3 injection (Reference 8-37), and \$15 to \$25/kW-yr for SCR (Reference 8-39). However, these latter two techniques have the potential for achieving lower NO_x emission levels from coal-firing, 129 ng/J (0.3 lb/10^6 Btu) for NH_3 injection, and 43 ng/J (0.1 lb/10^6 Btu) for SCR. These control levels assume that combustion modifications are already applied.

TABLE 8-17. PROJECTED CONTROL REQUIREMENTS FOR ALTERNATE NO_x EMISSION LEVELS

Fuel/NO_x Emission Level: ng/J (lb/10^6 Btu)	Recommended Control Requirement[a]	Cost to Control: \$/kW-yr[b] Retrofit	New Boiler
Coal			
301 (0.7)	OFA[c]	0.50 to 0.70	0.10 to 0.20
258 (0.6)	OFA[c]	0.50 to 0.70	0.10 to 0.20
215 (0.5)	LNB	0.40 to 0.50	0.30 to 0.40
172 (0.4)	OFA + LNB	0.95 to 1.20	0.40 to 0.50
Oil			
129 (0.3)	BOOS	0.50 to 0.60	N/A[d]
86 (0.2)	FGR + OFA	3.00	
Gas			
129 (0.3)	BOOS	0.50 to 0.60	N/A[d]
86 (0.2)	FGR + OFA	3.00	
43 (0.1)	FGR + OFA	3.00	

[a] LEA considered standard operating practice.
[b] Typical installation only; could be significantly higher. 1977 dollars.
[c] As manufacturers acquire more experience with LNB, they are now recommending LNB over OFA.
[d] N/A - Not applicable, no new oil- or gas-fired boilers being sold.

Advanced combustion modification concepts under development, such as the EPA advanced low NO_x burner (Reference 8-40) and EPRI primary combustion furnace (Reference 8-41), are targeted to achieve NO_x emissions levels below 86 ng/J (0.2 lb/10^6 Btu) on a commercial basis in the 1980's. Projected cost for the EPRI furnace is $5/kW or $0.80/kW-yr (Reference 8-42). The EPA advanced burner costs should fall in the same range between conventional combustion modification costs and the EPRI furnace costs (Reference 8-43). Thus developing advanced combustion modifications should eventually prove much more cost-effective than the developing postcombustion techniques; however, the latter techniques are currently closer to commercialization.

8.4.4 Concluding Remarks

Use of combustion modification NO_x controls should have no major adverse economic impact on the boiler manufacturing or utility industry. The four major boiler manufacturers all offer competitive designs of the preferred techniques for new boilers: off stoichiometric combustion and/or low NO_x burners (Reference 8-44). And the relatively low cost of combustion modifications, combined with accumulating favorable experience with their application, should aid in their acceptance by the utility sector (Reference 8-42).

8.5 EFFECTIVENESS OF NO_x CONTROLS

The effectiveness of combustion modifications NO_x controls has been examined in detail in Sections 4 through 6, with a detailed cost analysis in Section 7. This subsection highlights the major controls.

8.5.1 Coal-Fired Boilers

The most commonly applied low NO_x technique for coal-fired boilers is off stoichiometric combustion (OSC) through overfire air (OFA). Application of burners out of service (BOOS), an alternate staging technique, is limited because it is often accompanied by a 10 to 25 percent load reduction. Average NO_x reductions of 30 to 50 percent (controlled emissions of 215 to 301 ng/J, 0.5 to 0.7 lb/10^6 Btu) can be expected with either technique. Flue gas recirculation (FGR) has been tested, but was found to be a relatively ineffective control, giving only about 15 percent NO_x reduction. More recently, new low NO_x burners (LNB) have been installed on some units and have been found to be at least as effective as OFA. The combination of OFA with LNB has resulted in 40 to 60 percent NO_x

reductions (controlled emissions of 172 to 215 ng/J, 0.4 to 0.5 lb/10^6 Btu).

There has been a steady improvement in combustion modification control technology over recent years. Figure 8-4 conceptually reviews the past, current, and projected development of major controls. As shown, current demonstrated technology is capable of 40 to 60 percent NO_x reductions, readily meeting the current New Source Performance Standard (NSPS) of 258 ng/J (0.6 lb/10^6 Btu) for bituminous coal and 215 ng/J (0.5 lb/10^6Btu) for subbituminous coal. Current R&D programs, such as the EPA advanced low NO_x burner and the EPRI primary combustion furnace, should result in combustion modification techniques capable of meeting projected future NO_x emission control levels (1980's) of 86 ng/J (0.2 lb/10^6 Btu) to 129 ng/J (0.3 lb/10^6 Btu).

8.5.2 Oil-Fired Boilers

The most commonly used low NO_x techniques for oil-fired boilers are off stoichiometric combustion and flue gas recirculation (FGR), both employed with low excess air firing. Other techniques which have been tested are water injection (WI) and reduced air preheat (RAP). However, these latter two techniques have found little application due to attendant efficiency losses.

Off stoichiometric combustion has been applied through the use of overfire air ports (OFA) and by removing burners from service (BOOS). Typical NO_x reductions using OFA are 20 to 30 percent (controlled emissions of 150 to 172 ng/J, 0.35 to 0.4 lb/10^6 Btu), while BOOS has been slightly more effective giving 20 to 40 percent reductions (controlled levels of 129 to 172 ng/J, 0.3 to 0.4 lb/10^6 Btu). Flue gas recirculation also typically gives 20 to 30 percent NO_x reductions, but requires more hardware modifications. The combination of BOOS or OFA with FGR has been most effective, resulting in 30 to 60 percent reductions (controlled emissions of 86 to 172 ng/J, 0.2 to 0.4 lb/10^6 Btu). With FGR, OFA is preferred over BOOS because flame stability is expected to be more of a problem with the combination of FGR + BOOS.

There has been some R&D effort by EPA and private industry on low NO_x emission burners for oil-firing. One manufacturer has reported the successful retrofit of an oil-fired low NO_x burner, producing NO_x emissions of below 129 ng/J (0.3 lb/10^6 Btu) (Reference 8-45). The

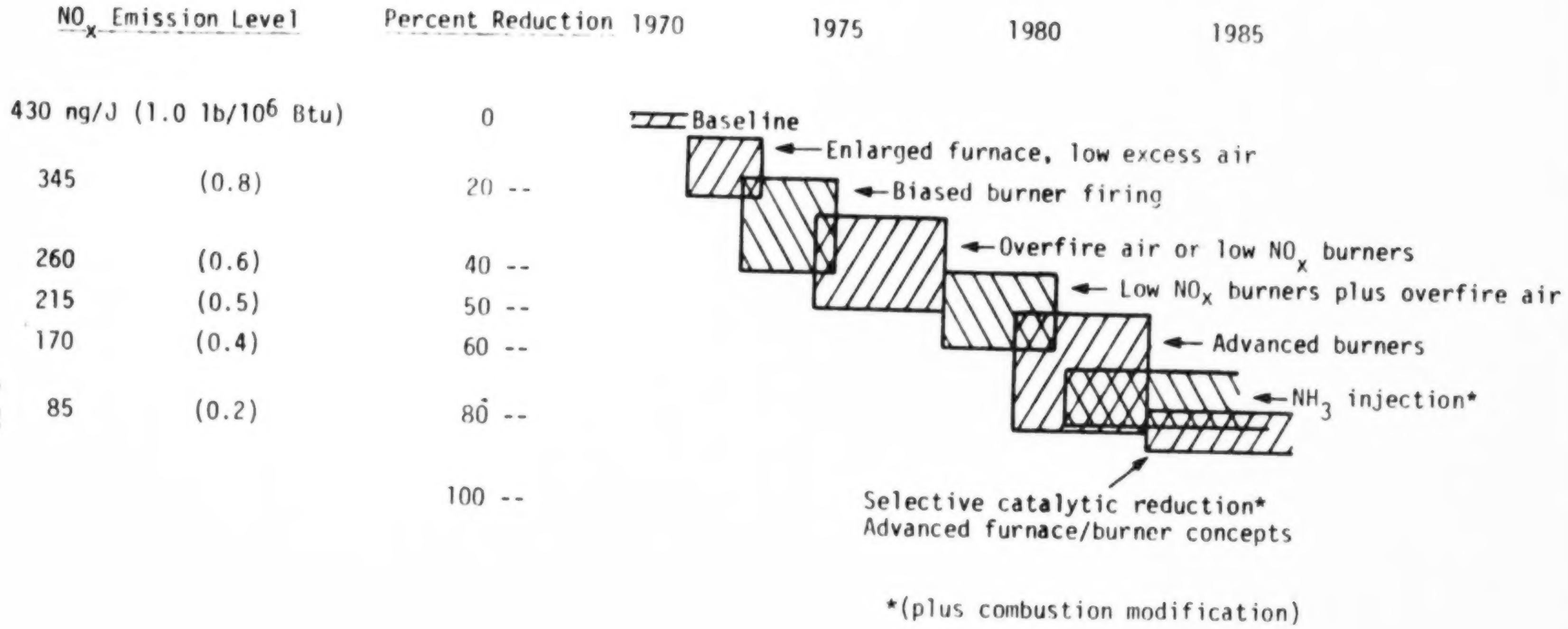

Figure 8-4. NO$_x$ control development for coal-fired boilers.

combination of overfire air and low emissions burners may potentially achieve emissions below 86 ng/J (0.2 lb/10^6 Btu).

8.5.3 Gas-Fired Boilers

The most commonly applied NO_x control techniques for gas-fired boilers, as with oil-fired boilers, are staged combustion through the use of OFA or BOOS with FGR; however, flame stability may be of greater concern when FGR is combined with BOOS. Typical NO_x reduction under either OFA, BOOS, or FGR are 30 to 60 percent (controlled emissions of 86 to 150 ng/J, 0.2 to 0.35 lb/10^6 Btu). The combination of staged combustion and FGR is capable of 50 to 80 percent reductions (controlled levels of 43 to 108 ng/J, 0.1 to 0.25 lb/10^6 Btu).

There are no major efforts toward developing a low NO_x burner or other new combustion modification techniques for gas-firing because NO_x emissions under current control techniques are already relatively low, and no new gas-fired utility boilers are being sold currently.

8.6 CONCLUSIONS AND RECOMMENDATIONS

Combustion modification NO_x controls are cost-effective techniques, causing no apparent major adverse environmental impacts. It is recommended that data acquisition from long term NO_x control applications continue, in order to eliminate potential areas of concern and optimize boiler performance.

8.6.1 Conclusions

Modifying the combustion process conditions is currently the most cost-effective and best demonstrated method of effecting 20 to 60 percent reductions in NO_x emissions from utility boilers. Table 8-18 summarizes the capabilities of combustion modification NO_x controls. The methods in the best available control technology (BACT) and advanced technology categories are listed in preference of application. They were selected based on an assessment of their effectiveness (Sections 4 through 6), operational (Section 6), energy (Section 6), cost (Section 7), and environmental (Section 8) impact, and commercial availability or R&D status (Section 4).

In the BACT category, low NO_x burners (LNB) or off stoichiometric combustion (OSC) through overfire air addition (OFA) are the preferred techniques for retrofit application to coal-fired units. The actual choice would be determined on a site-specific basis, depending on the fuel/furnace

TABLE 8-18. COMBUSTION MODIFICATION NO_x CONTROLS: BEST AVAILABLE CONTROL TECHNOLOGY (BACT) AND ADVANCED TECHNOLOGY

	Fuel	Control Technique	NO_x Control Level, ng/J (lb/10^6 Btu)	
BACT	Coal	Overfire air[a]	258	(0.6)
		Low NO_x burners	215	(0.5)
		Low NO_x burners plus overfire air	172	(0.4)
	Oil	Burners out of service or overfire air	129	(0.3)
		Flue gas recirculation plus overfire air	86	(0.2)
	Gas	Burners out of service or overfire air	129	(0.3)
		Flue gas recirculation plus overfire air	43	(0.1)
Advanced Technology	Coal	Ammonia injection (1983)[b] (combined with BACT combustion modifications)	129	(0.3)
		Advanced low NO_x burners (1985)	86	(0.2)
		Advanced burner/furnace concepts (1985)	60	(0.15)
	Oil	Ammonia injection (1983) (combined with BACT combustion modifications)	43	(0.1)

[a] As manufacturers acquire more experience with LNB, they are now recommending LNB over OFA.

[b] Estimated date of commercial availability of demonstrated technology.

design, etc. The use of low NO_x burners, or low NO_x burners in combination with OFA is favored. For new units, off stoichiometric combustion through OFA or removing burners from service, flue gas recirculation, or the combination of FGR with OSC is recommended for retrofit application to oil- and gas-fired boilers. No sales of new oil- or gas-fired units are projected.

While BACT can achieve 172 ng/J (0.4 lb/10^6 Btu) for coal-firing, 86 ng/J (0.2 lb/10^6 Btu) for oil-firing, and 43 ng/J (0.1 lb/10^6 Btu) for gas-firing, Table 8-18 indicates that advanced techniques have the potential of reducing NO_x to 86 ng/J (0.2 lb/10^6 Btu) for coal and 43 ng/J (0.1 lb/10^6 Btu) for oil. However, ammonia injection, advanced low NO_x burners, and advanced burner/furnace concepts are several years away. Ammonia injection is considered a near-term intermediate control option between BACT and the more distant advanced concepts, intermediate from the point of view of control effectiveness and availability. However, ammonia injection has many potential operational and environmental hazards that need to be assessed, as discussed in Section 4, as well as much higher projected costs than either BACT or the more promising advanced concepts, as noted in Section 7.

The use of conventional combustion modifications (BACT) has potential for adverse effects on boiler efficiency, load capacity, water wall tube corrosion, slagging, fouling, carbon loss, steam temperature, flame stability, and vibration. However, recent field experience has shown that adverse effects can be minimized to acceptable levels with proper care in design for retrofit application, and largely eliminated in new unit designs.

Another area of concern with combustion modification NO_x controls is a possible increase in incremental emissions of other pollutants to the environment. Recent test data with BACT techniques seem to indicate that low NO_x firing has negligible effects on emissions of most pollutants other than NO_x. Based on the comprehensive environmental assessment test run on a 180 MW boiler, low NO_x firing does indeed lower the overall potential environmental impact of the source. However, there are areas of continued concern, such as possible increased organic emissions. More extensive field testing will be required to identify and better quantify these emissions, and compare these results with developing information in the health effects area.

Finally, conventional combustion modifications are indeed cost-effective means of control for NO_x, raising the cost of electricity less than one percent in most cases. Furthermore, the initial capital investment required should also only be of the order of 1 percent or less of the installed cost of a boiler. With the exception of NH_3 injection, advanced techniques such as advanced low NO_x burners and advanced burner/furnace concepts have projected costs in the same range as conventional combustion modifications. Therefore, preferred current and projected combustion modification techniques are not expected to have any significant adverse economic impact.

8.6.2 Recommendations

Preferred conventional combustion modifications are indeed recommended for reducing NO_x emissions from utility boilers, with minimal adverse environmental, operational, and cost impacts. However, long-term testing and monitoring of field applications/demonstrations should be continued. Although the issue of possible increased corrosion with off stoichiometric combustion has been largely resolved in short-term tests, long-term corrosion testing, as under current EPA programs, should be completed to definitively establish that low NO_x firing does not have any adverse effects. Boiler efficiency should be closely monitored during field applications to give guidance to control developers on minimizing or eliminating efficiency losses. The current data base indicates that efficiency losses of up to 0.5 percent are possible. The exact number is of significance; for example, a 0.25 percent loss in efficiency can translate to one-third of the annualized cost to control.

Finally, the data gaps on the effect of NO_x controls on incremental emissions are just now beginning to be addressed. Field testing on representative utility boiler/control applications should continue, with special emphasis on incremental emissions such as trace metals and organics.

Research and development efforts on new combustion modification technology, such as advanced staged combustion, low NO_x burners and burner/furnace concepts, should continue since they have the potential of further NO_x reduction capabilities with minimal adverse impacts.

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